EXHIBIT C

US008881833B2

(12) **United States Patent**
Radford et al.

(10) **Patent No.: US 8,881,833 B2**
(45) **Date of Patent: Nov. 11, 2014**

(54) **REMOTELY CONTROLLED APPARATUS FOR DOWNHOLE APPLICATIONS AND METHODS OF OPERATION**

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(73) Assignee: **Baker Hughes Incorporated**, Houston, TX (US)

(*) Notice: Subject to any disclaimer, the term of this patent is extended or adjusted under 35 U.S.C. 154(b) by 436 days.

(21) Appl. No.: **12/895,233**

(22) Filed: **Sep. 30, 2010**

(65) **Prior Publication Data**

US 2011/0127044 A1 Jun. 2, 2011

Related U.S. Application Data

(60) Provisional application No. 61/247,162, filed on Sep. 30, 2009, provisional application No. 61/377,146, filed on Aug. 26, 2010.

(51) **Int. Cl.**

E21B 23/00	(2006.01)
E21B 10/32	(2006.01)
E21B 47/12	(2012.01)
E21B 17/10	(2006.01)

(52) **U.S. Cl.**

CPC ***E21B 10/322*** (2013.01); ***E21B 47/12*** (2013.01); ***E21B 17/1014*** (2013.01)

USPC **166/382**; 175/319

(58) **Field of Classification Search**

USPC 166/382, 373; 175/217, 319

See application file for complete search history.

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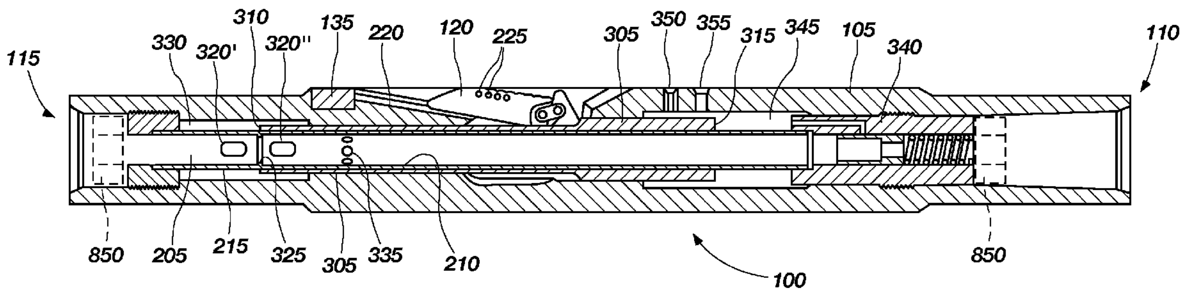
Primary Examiner — Cathleen Hutchins
(74) *Attorney, Agent, or Firm* — TraskBritt

(57) **ABSTRACT**

An apparatus for use downhole is disclosed that, in one configuration includes a downhole tool configured to operate in an active position and an inactive position and an actuation device, which may include a control unit. The apparatus includes a telemetry unit that sends a first pattern recognition signal to the control unit to move the tool into the active position and a second pattern recognition signal to move the tool into the inactive position. The apparatus may be used for drilling a subterranean formation and include a tubular body and one or more extendable features, each positionally coupled to a track of the tubular body, and a drilling fluid flow path extending through a bore of the tubular body for conducting drilling fluid therethrough. A push sleeve is disposed within the tubular body and coupled to the one or more features. A valve assembly is disposed within the tubular body and configured to control the flow of the drilling fluid into an annular chamber in communication with the push sleeve; the valve assembly comprising a mechanically operated valve and/or an electronically operated valve. Other embodiments, including methods of operation, are provided.

30 Claims, 15 Drawing Sheets



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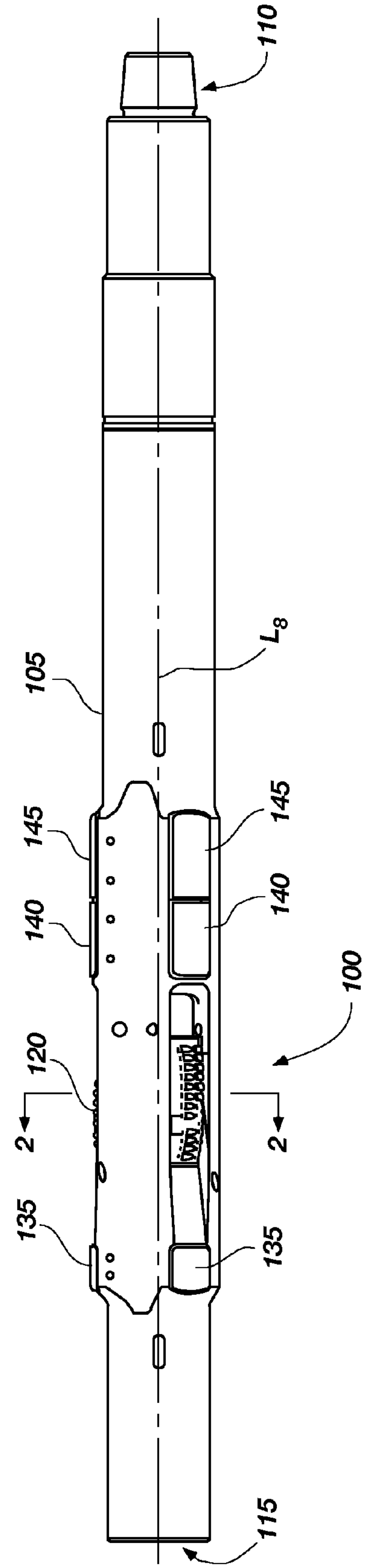

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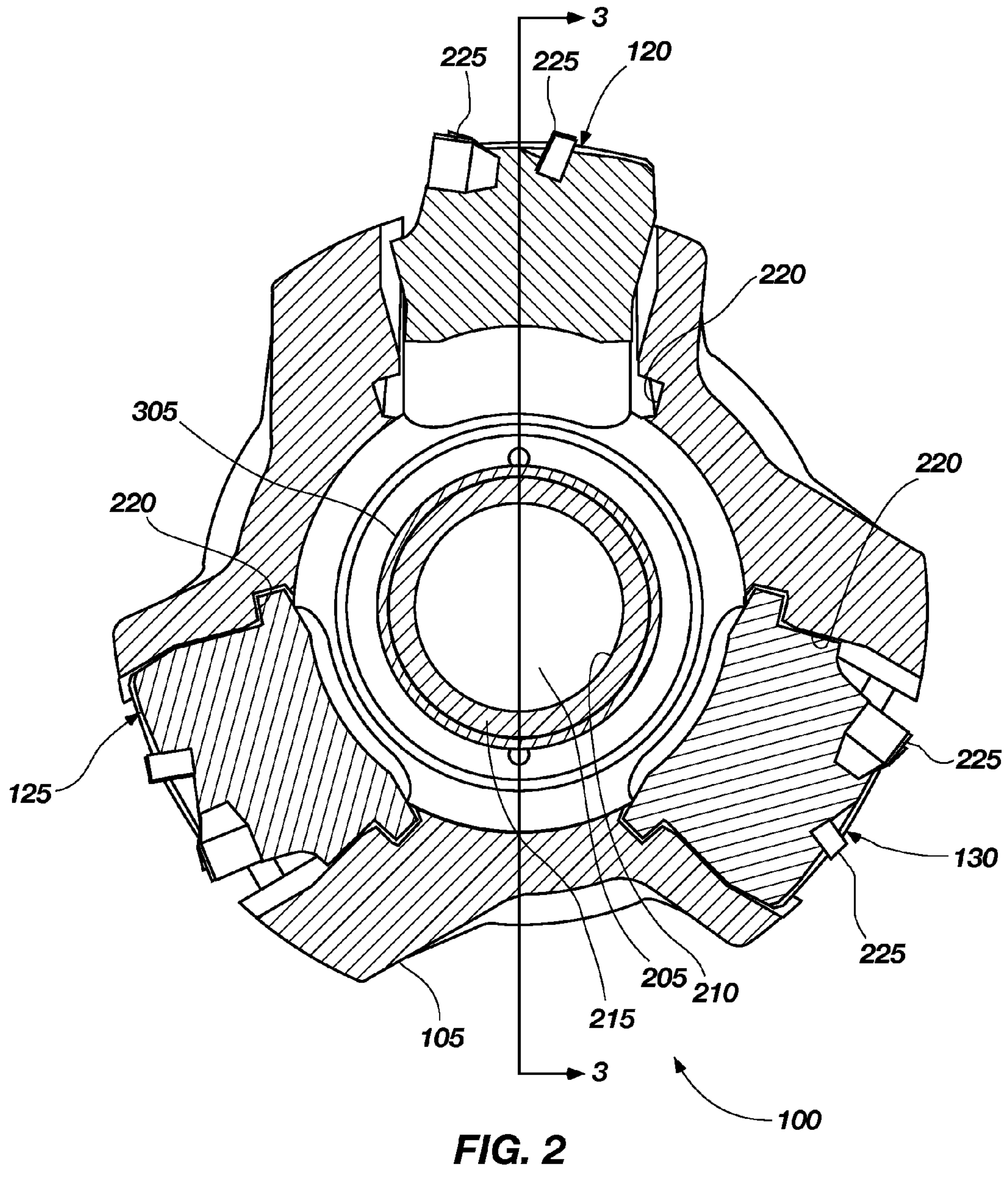
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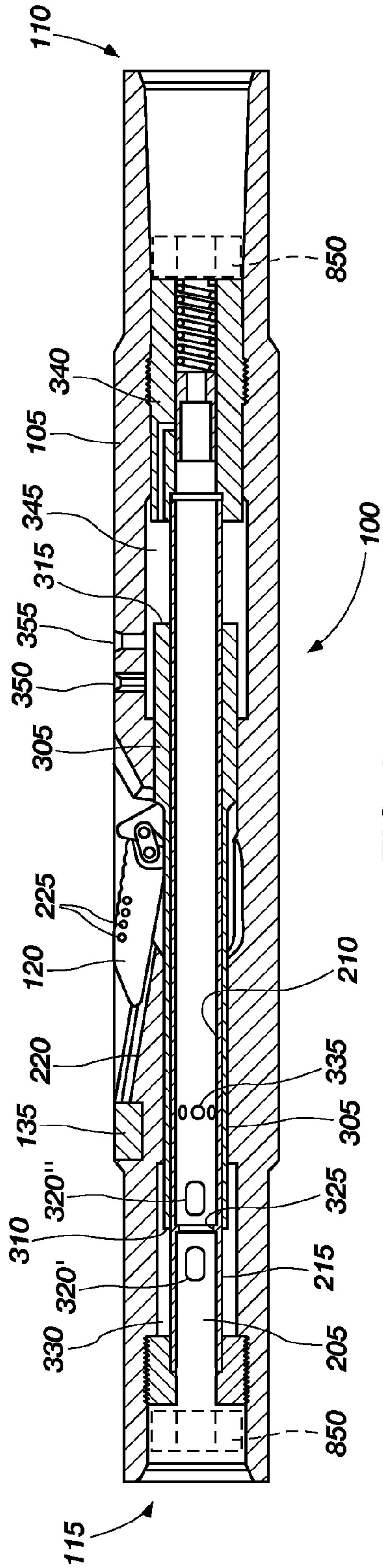
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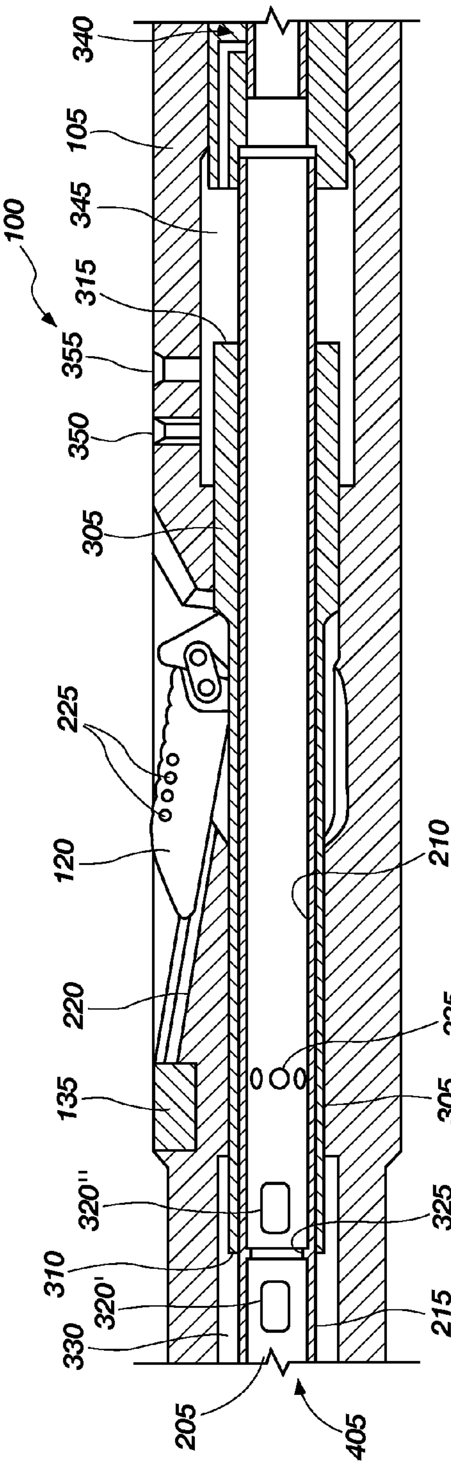
FIG. 3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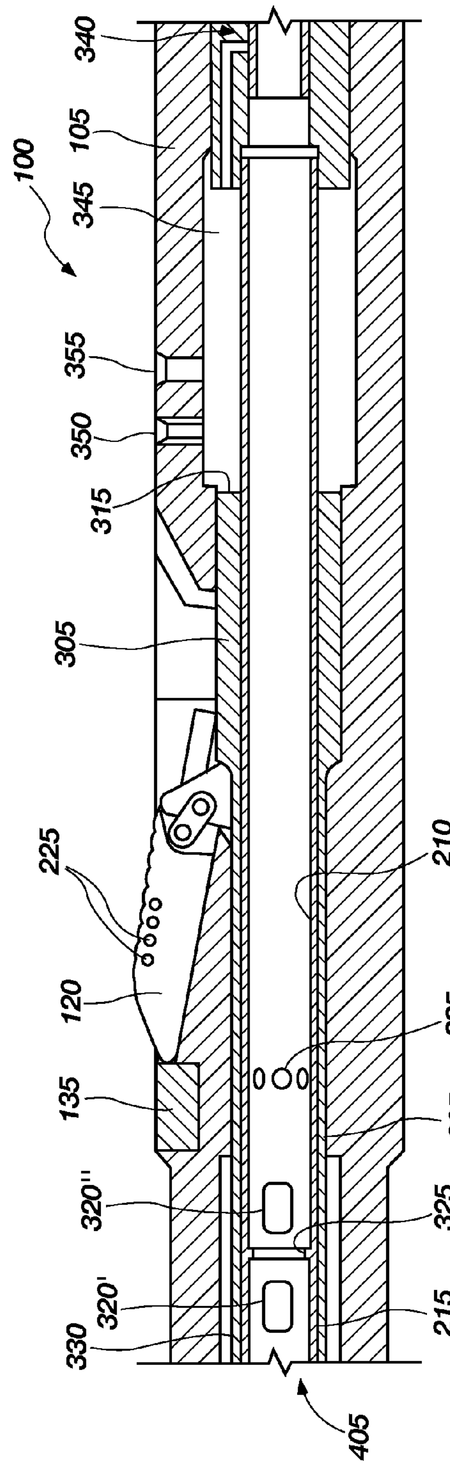
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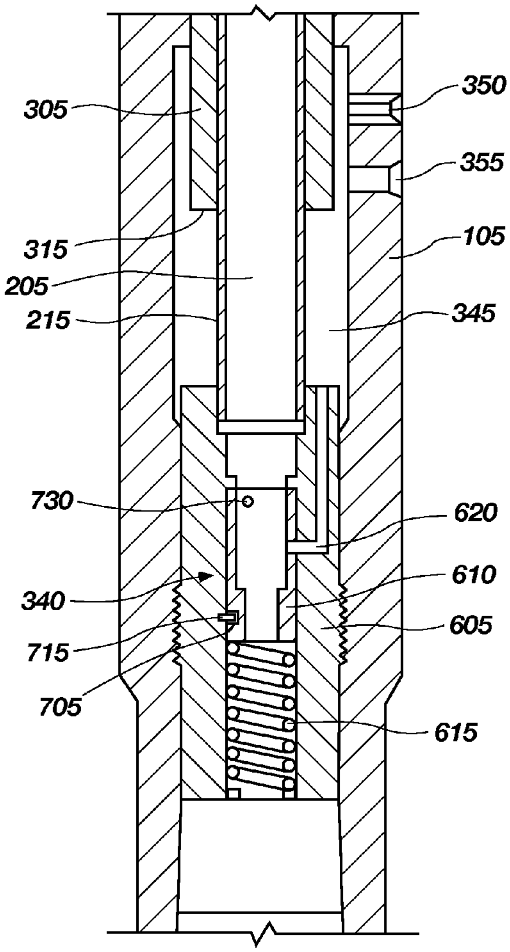
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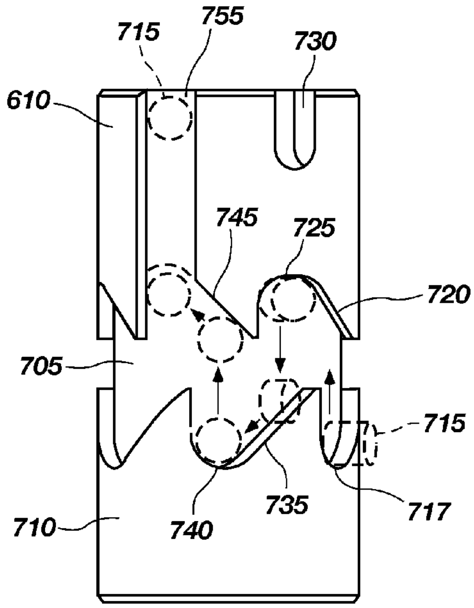
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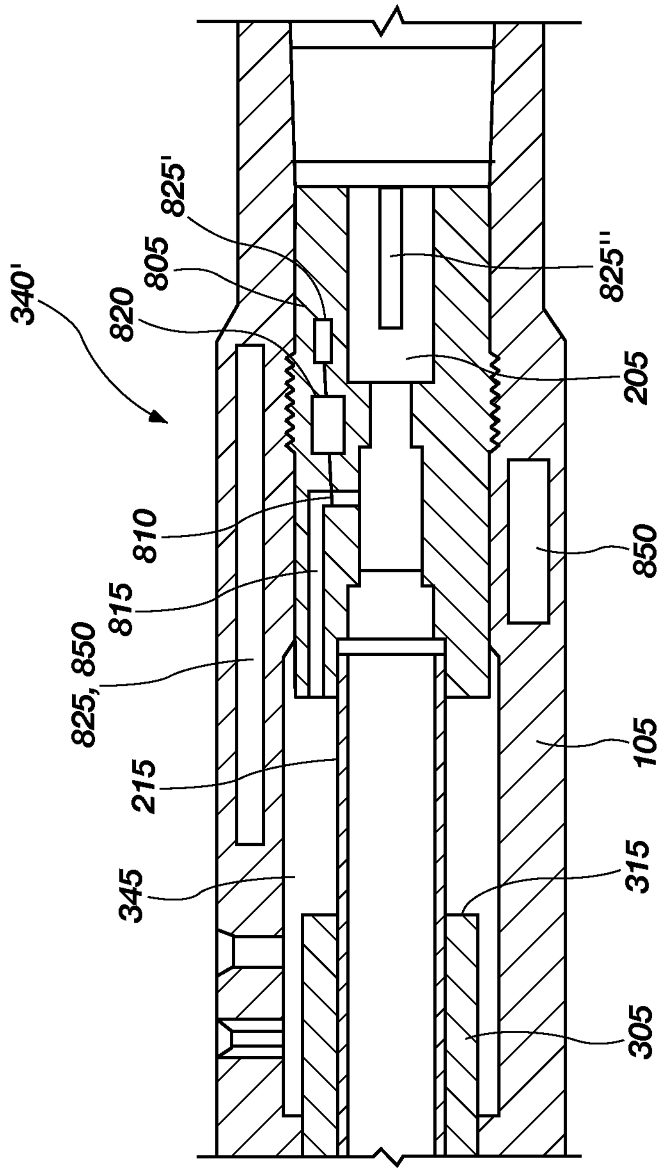

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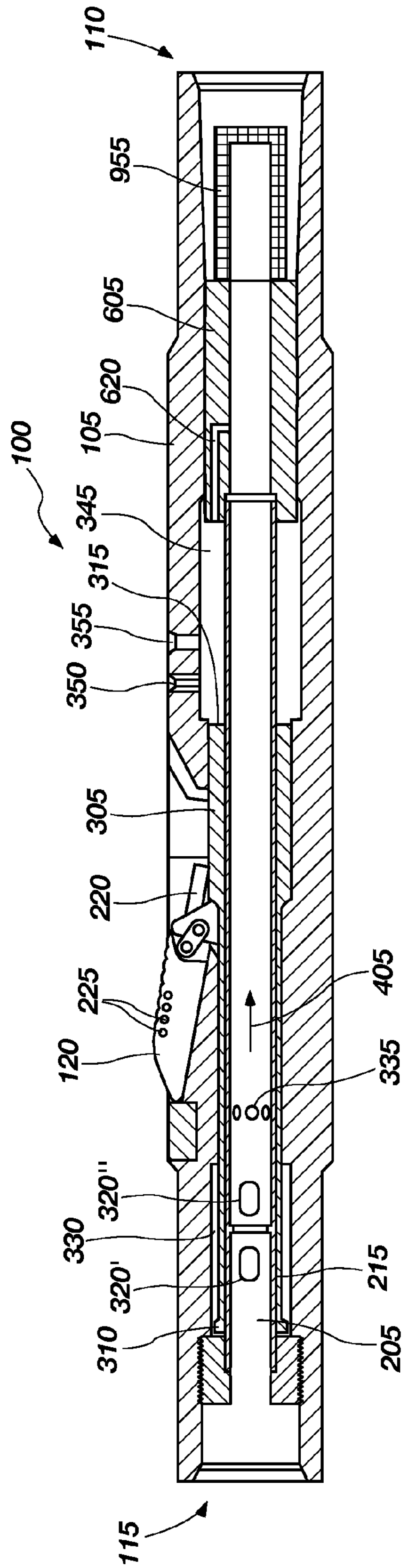
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FIG. 9

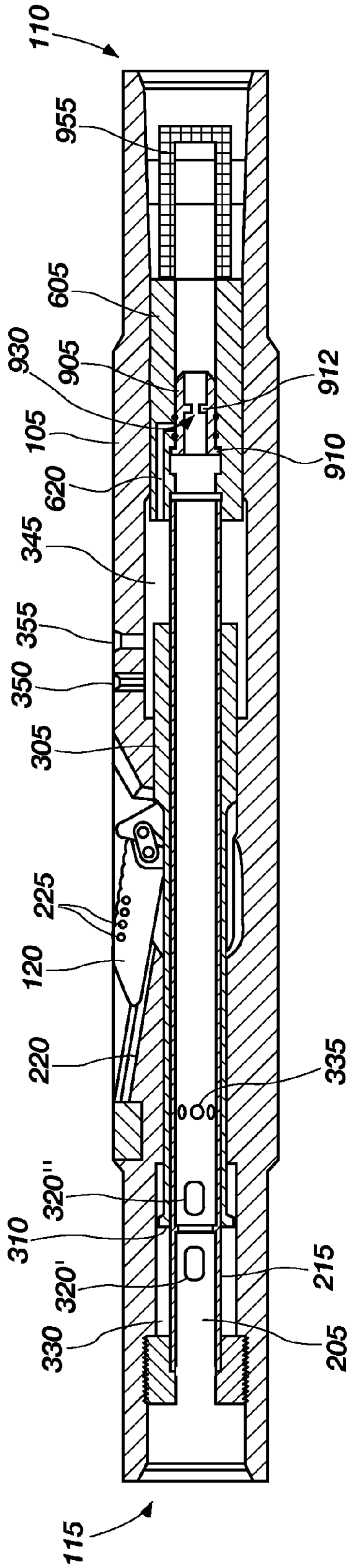

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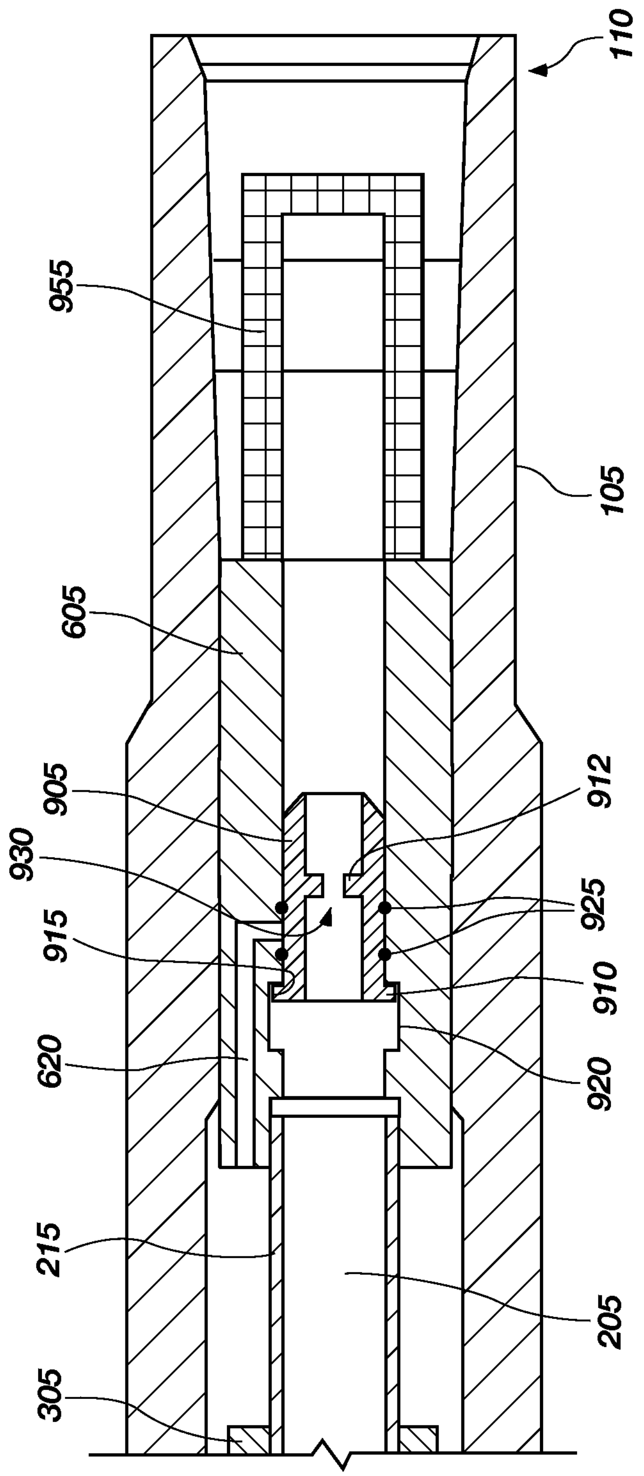
FIG. 10



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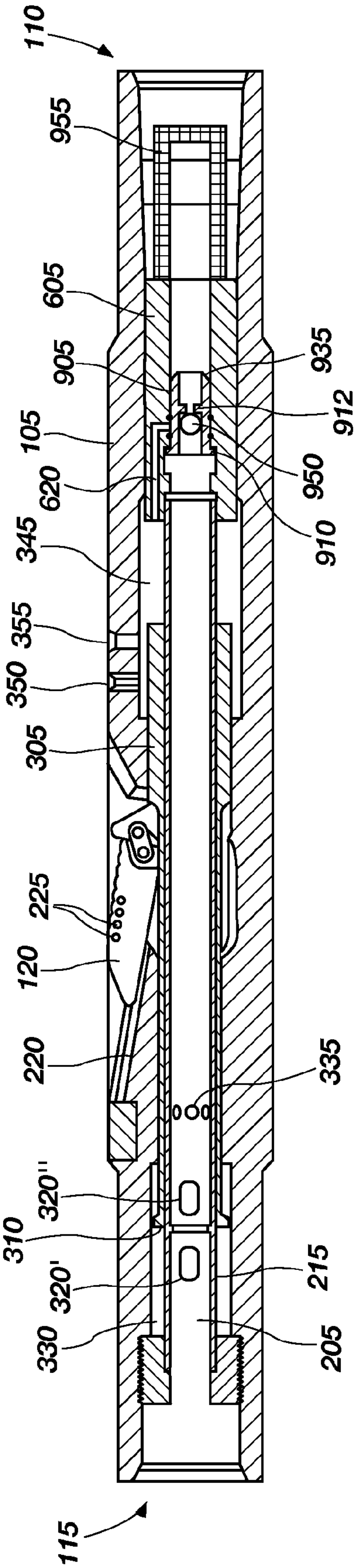
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FIG. 12

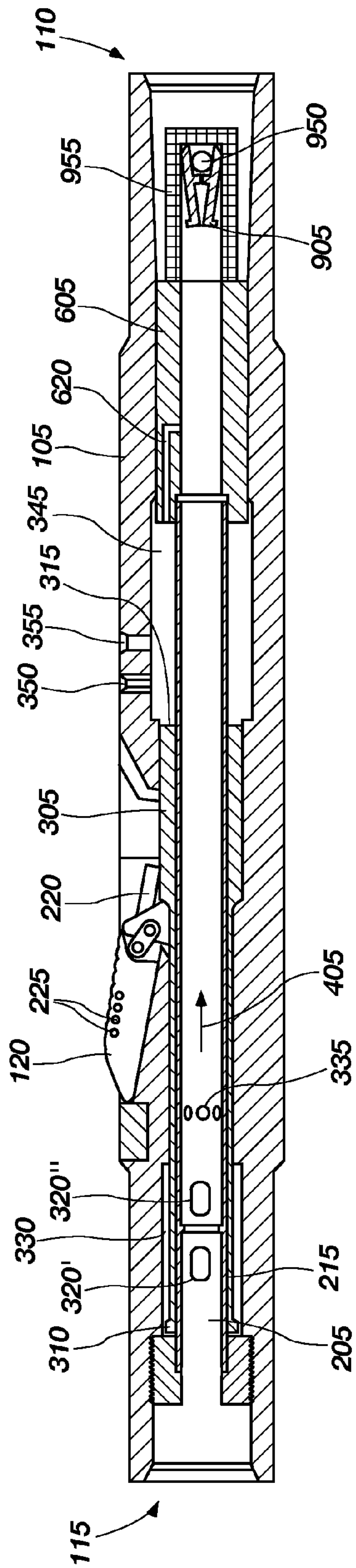

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FIG. 13

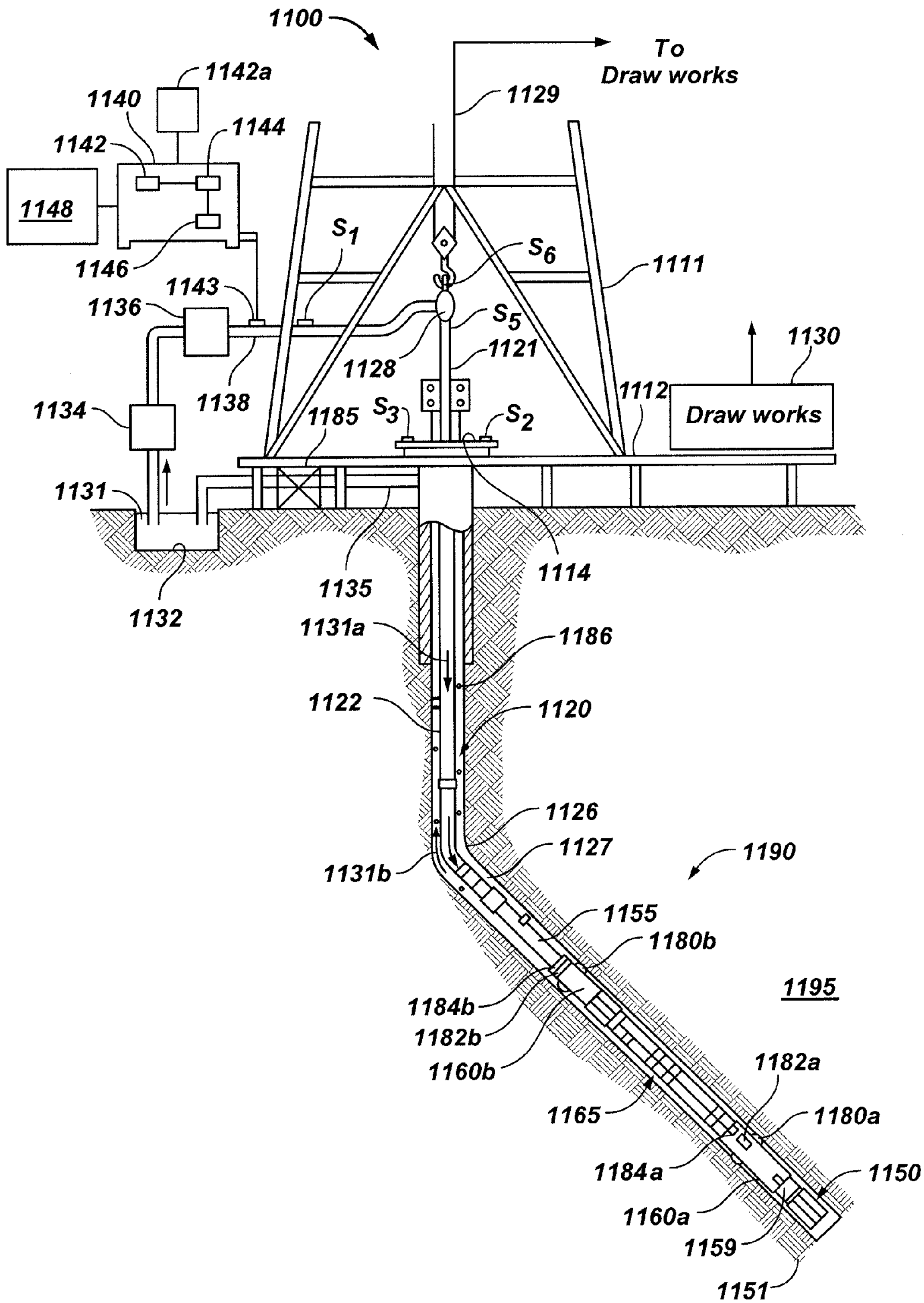
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FIG. 14

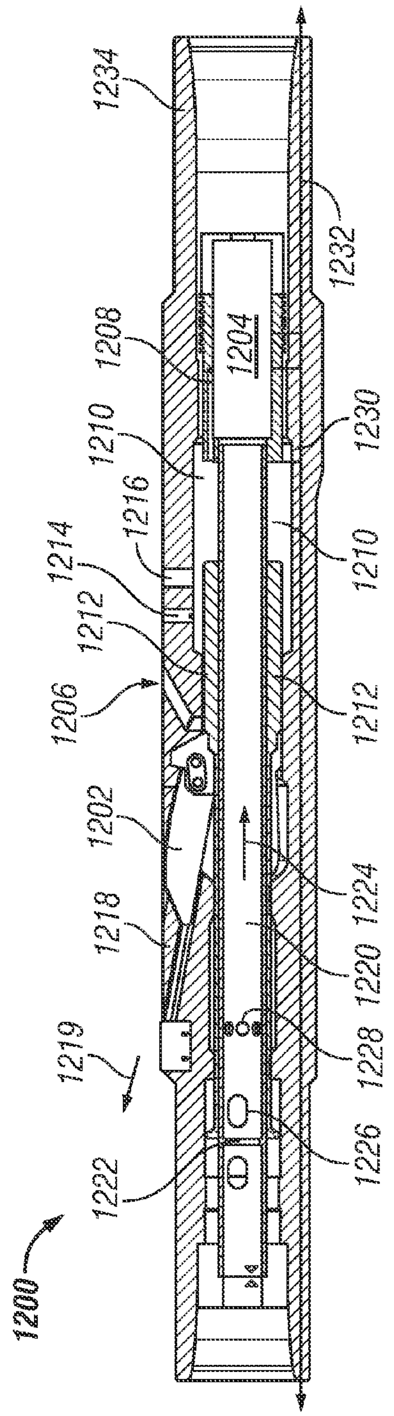

FIG. 15A

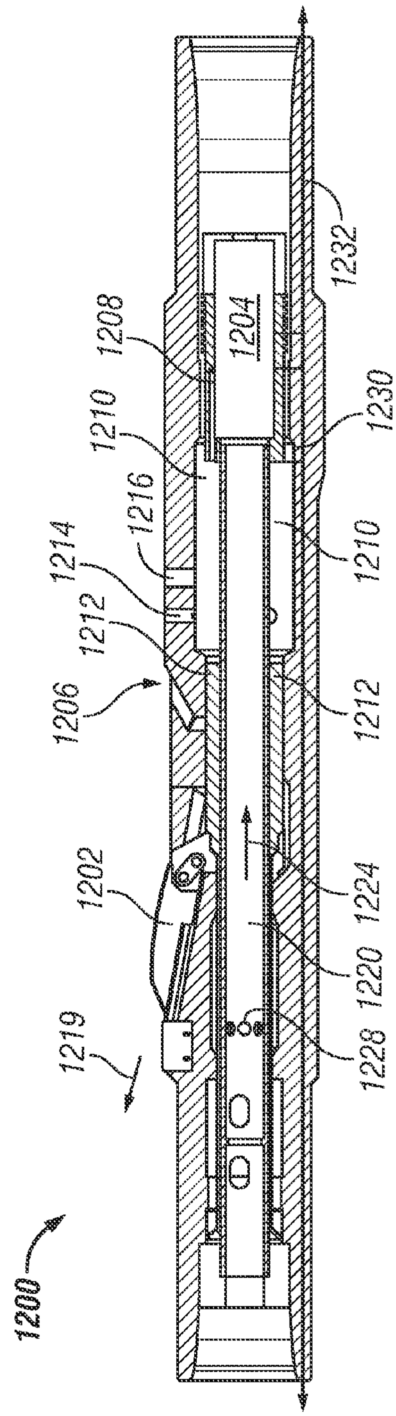

FIG. 15B

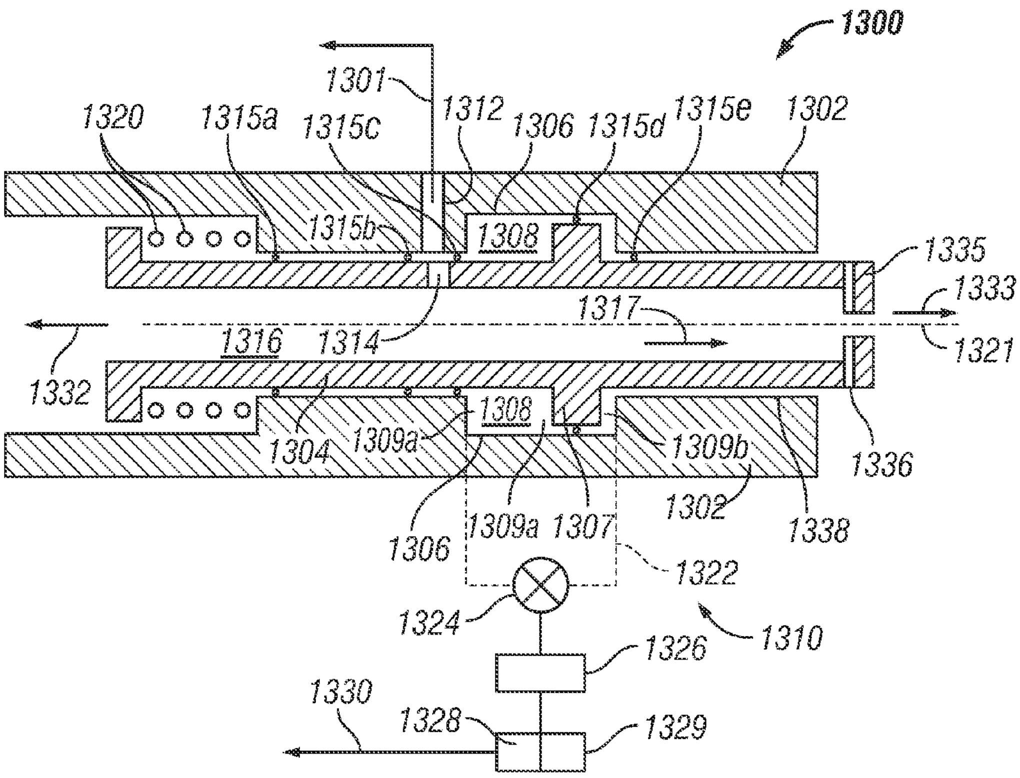
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FIG. 16A

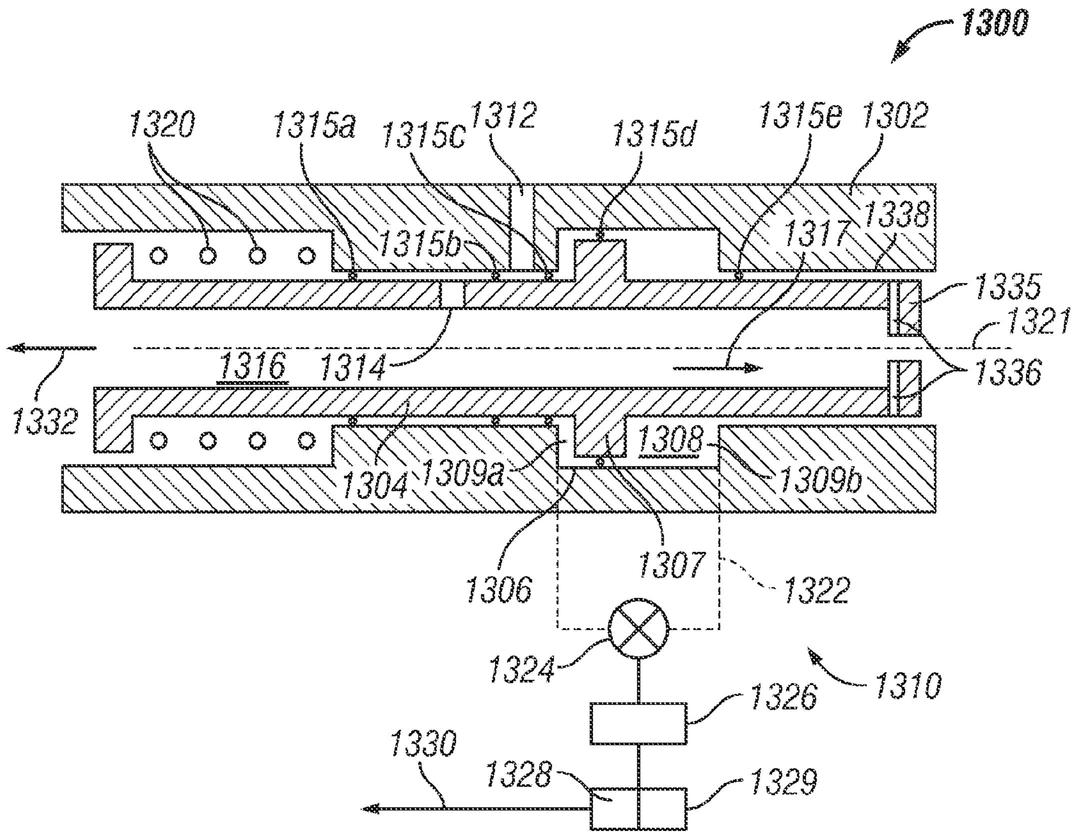
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FIG. 16B

REMOTELY CONTROLLED APPARATUS FOR DOWNHOLE APPLICATIONS AND METHODS OF OPERATION

CROSS-REFERENCE TO RELATED APPLICATIONS

This application claims the benefit of U.S. Provisional Application Ser. No. 61/247,162, filed Sep. 30, 2009, entitled "Remotely Activated and Deactivated Expandable Apparatus for Earth Boring Applications," and claims the benefit of U.S. Provisional Patent Application Ser. No. 61/377,146, entitled "Remotely-Controlled Device and Method for Downhole Actuation" filed Aug. 26, 2010, the disclosure of each of which of the foregoing applications is hereby incorporated herein by this reference in its entirety.

TECHNICAL FIELD

Embodiments of the present invention relate generally to remotely controlled apparatus for use in a subterranean borehole and, more particularly, in some embodiments to an expandable reamer apparatus for enlarging a subterranean borehole, to an expandable stabilizer apparatus for stabilizing a bottom hole assembly during a drilling operation, in other embodiments to other apparatus for use in a subterranean borehole, and in still other embodiments to an actuation device and system.

BACKGROUND

Wellbores, also called boreholes, for hydrocarbon (oil and gas) production, as well as for other purposes, such as, for example, geothermal energy production, are drilled with a drill string that includes a tubular member (also referred to as a drilling tubular) having a drilling assembly (also referred to as the drilling assembly or bottom hole assembly or "BHA") which includes a drill bit attached to the bottom end thereof. The drill bit is rotated to shear or disintegrate material of the rock formation to drill the wellbore. The drill string often includes tools or other devices that need to be remotely activated and deactivated during drilling operations. Such tools and devices include, among other things, reamers, stabilizers or force application members used for steering the drill bit, Production wells include devices, such as valves, inflow control device, etc., that are remotely controlled. The disclosure herein provides a novel apparatus for controlling such and other downhole tools or devices.

Expandable tools are typically employed in downhole operations in drilling oil, gas and geothermal wells. For example, expandable reamers are typically employed for enlarging a subterranean borehole. Conventionally in drilling oil, gas, and geothermal wells, a casing string (such term broadly including a liner string) is installed and cemented to prevent the wellbore walls from caving into the subterranean borehole while providing requisite shoring for subsequent drilling operations to achieve greater depths. Casing is also conventionally installed to isolate different formations, to prevent crossflow of formation fluids, and to enable control of formation fluids and pressure as the borehole is drilled. To increase the depth of a previously drilled borehole, new casing is laid within and extended below the previous casing. While adding additional casing allows a borehole to reach greater depths, it has the disadvantage of narrowing the borehole. Narrowing the borehole restricts the diameter of any subsequent sections of the well because the drill bit and any further casing must pass through the existing casing. As

reductions in the borehole diameter are undesirable because they limit the production flow rate of oil and gas through the borehole, it is often desirable to enlarge a subterranean borehole to provide a larger borehole diameter for installing additional casing beyond previously installed casing as well as to enable better production flow rates of hydrocarbons through the borehole.

A variety of approaches have been employed for enlarging a borehole diameter. One conventional approach used to enlarge a subterranean borehole includes using eccentric and bi-center bits. For example, an eccentric bit with a laterally extended or enlarged cutting portion is rotated about its axis to produce an enlarged borehole diameter. A bi-center bit assembly employs two longitudinally superimposed bit sections with laterally offset longitudinal axes, which when the bit is rotated produce an enlarged borehole diameter.

Another conventional approach used to enlarge a subterranean borehole includes employing an extended bottom hole assembly with a pilot drill bit at the distal end thereof and a reamer assembly some distance above. This arrangement permits the use of any standard rotary drill bit type, be it a rock bit or a drag bit, as the pilot bit, and the extended nature of the assembly permits greater flexibility when passing through tight spots in the borehole as well as the opportunity to effectively stabilize the pilot drill bit so that the pilot hole and the following reamer will traverse the path intended for the borehole. This aspect of an extended bottom hole assembly is particularly significant in directional drilling. One design to this end includes so-called "reamer wings," which generally comprise a tubular body having a fishing neck with a threaded connection at the top thereof and a tong die surface at the bottom thereof, also with a threaded connection. The upper midportion of the reamer wing tool includes one or more longitudinally extending blades projecting generally radially outwardly from the tubular body, the outer edges of the blades carrying PDC cutting elements.

As mentioned above, conventional expandable reamers may be used to enlarge a subterranean borehole and may include blades pivotably or hingedly affixed to a tubular body and actuated by way of a piston disposed therein. In addition, a conventional borehole opener may be employed comprising a body equipped with at least two hole opening arms having cutting means that may be moved from a position of rest in the body to an active position by exposure to pressure of the drilling fluid flowing through the body. The blades in these reamers are initially retracted to permit the tool to be run through the borehole on a drill string and once the tool has passed beyond the end of the casing, the blades are extended so the bore diameter may be increased below the casing.

The blades of some conventional expandable reamers have been sized to minimize a clearance between themselves and the tubular body in order to prevent any drilling mud and earth fragments from becoming lodged in the clearance and binding the blade against the tubular body. The blades of these conventional expandable reamers utilize pressure from inside the tool to apply force radially outward against pistons which move the blades, carrying cutting elements, laterally outward. It is felt by some that the nature of some conventional reamers allows misaligned forces to cock and jam the pistons and blades, preventing the springs from retracting the blades laterally inward. Also, designs of some conventional expandable reamer assemblies fail to help blade retraction when jammed and pulled upward against the borehole casing. Furthermore, some conventional hydraulically actuated reamers utilize expensive seals disposed around a very complex shaped and expensive piston, or blade, carrying cutting elements. In order to prevent cocking, some conventional ream-

ers are designed having the piston shaped oddly in order to try to avoid the supposed cocking, requiring matching, complex seal configurations. These seals are feared to possibly leak after extended usage.

Notwithstanding the various prior approaches to drill and/or ream a larger diameter borehole below a smaller diameter borehole, the need exists for improved apparatus and methods for doing so. For instance, bi-center and reamer wing assemblies are limited in the sense that the pass through diameter of such tools is nonadjustable and limited by the reaming diameter. Furthermore, conventional bi-center and eccentric bits may have the tendency to wobble and deviate from the path intended for the borehole. Conventional expandable reaming assemblies, while sometimes more stable than bi-center and eccentric bits, may be subject to damage when passing through a smaller diameter borehole or casing section, may be prematurely actuated, and may present difficulties in removal from the borehole after actuation.

BRIEF SUMMARY

Various embodiments of the present disclosure are directed to expandable apparatuses. In one or more embodiments, an expandable apparatus may comprise a tubular body comprising a fluid passageway extending through an inner bore. A push sleeve may be disposed within the inner bore of the tubular body and may be coupled to one or more expandable features. The push sleeve may comprise a lower surface in communication with a lower annular chamber. The push sleeve may be configured to move axially responsive to a flow of drilling fluid through the fluid passageway to extend and retract the one or more expandable features. A valve may be positioned within the tubular body and configured to selectively control the flow of a drilling fluid into the lower annular chamber.

In one or more additional embodiments, an expandable apparatus may comprise a tubular body and one or more expandable features. The one or more expandable features are configured to expand and retract an unlimited number of times. The expandable apparatus may be configured as an expandable reamer, an expandable stabilizer, or other expandable apparatus.

Additional embodiments of the disclosure are directed to methods of operating an expandable apparatus. One or more embodiments of such methods may comprise flowing a drilling fluid through a fluid passageway located in a tubular body of an expandable apparatus. A force may be exerted on the push sleeve disposed within the tubular body sufficient to bias the push sleeve axially downward and to retract one or more expandable features coupled to the push sleeve. A valve coupled to a valve port that extends between the fluid passageway and a lower annular chamber may be opened and drilling fluid may flow into the lower annular chamber in communication with a lower surface of the push sleeve. A force may be exerted by the drilling fluid on the lower surface of the push sleeve, moving the push sleeve axially upward and expanding the one or more expandable features coupled to the push sleeve.

In one or more additional embodiments, a method of operating an expandable apparatus may comprise expanding at least one expandable feature coupled to a tubular body and retracting the at least one expandable feature. The foregoing sequence of expanding and retracting can be repeated an unlimited number of times.

Still other embodiments of the disclosure comprise push sleeves employable with an expandable apparatus. In one or more embodiments, such push sleeves may comprise means for coupling the push sleeve to one or more expandable features. The push sleeve may further include an upper annular surface and a lower annular surface, the lower annular surface comprising a larger surface area than the upper annular surface.

In a further embodiment, an apparatus for use downhole is disclosed that in one configuration includes a downhole tool configured to move between a first mode and second mode which, for some applications, may be further respectively characterized as an inactive position and an active position.

In yet a further embodiment, an actuation device includes a housing including an annular chamber configured to house a first fluid therein, a piston in the annular chamber configured to divide the annular chamber into a first section and a second section, the piston being coupled to a biasing member, and a control unit configured to move the first fluid from the first section to the second section to supply a second fluid under pressure to a downhole tool to move the tool into the active position and from the second section to the first section to stop the supply of the second fluid to the tool to cause the tool to move into the inactive position.

In another embodiment, the apparatus comprises a system including a telemetry unit that sends a first pattern recognition signal to the control unit to move the tool into the active position and a second pattern recognition signal to move the tool into the inactive position.

BRIEF DESCRIPTION OF THE DRAWINGS

FIG. **1** is a side view of an embodiment of an expandable apparatus of the disclosure.

FIG. **2** shows a transverse cross-sectional view of the expandable apparatus as indicated by section line **2-2** in FIG. **1**.

FIG. **3** shows a longitudinal cross-sectional view of the expandable apparatus shown in FIG. **1**.

FIG. **4** shows an enlarged longitudinal cross-sectional view of a portion of the expandable apparatus shown in FIG. **3**.

FIG. **5** shows an enlarged cross-sectional view of the same portion of the expandable apparatus shown in FIG. **4** and with the blades expanded.

FIG. **6** shows an enlarged cross-sectional view of a valve according to at least one embodiment for a mechanically controlled valve.

FIG. **7** shows a side view of a valve cylinder according to an embodiment of the valve shown in FIG. **6**.

FIG. **8** shows an enlarged cross-sectional view of a valve according to at least one embodiment for an electronically controlled valve.

FIG. **9** shows a longitudinal cross-sectional view of a further embodiment of the expandable apparatus configured to employ a trap sleeve and a flow restricting element.

FIG. **10** shows an enlarged cross-sectional view of the lower end of the expandable apparatus of FIG. **9**.

FIG. **11** shows a longitudinal cross-sectional view of the expandable apparatus of FIG. **9** with a trap sleeve in place.

FIG. **12** shows a longitudinal cross-sectional view of the expandable apparatus of FIG. **9** with a trap sleeve in place and a flow restriction element retained in the trap sleeve.

FIG. **13** shows a longitudinal cross-sectional view of the expandable apparatus of FIG. **9** with a trap sleeve and a flow restriction element released and retained in a screen catcher.

FIG. **14** is an elevation view of a drilling system including an actuation device, according to an embodiment of the disclosure.

FIGS. **15**A and **15**B are sectional side views of an embodiment of a portion of a drill string, a tool and an actuation

device, wherein the tool is depicted in two positions, according to an embodiment of the disclosure.

FIGS. **16**A and **16**B are sectional schematic views of an actuation device in two states or positions, according to an embodiment of the disclosure.

DETAILED DESCRIPTION

The illustrations presented herein are, in some instances, not actual views of any particular expandable apparatus, but are merely idealized representations that are employed to describe the present invention. Additionally, elements common between figures may retain the same numerical designation.

Various embodiments of the disclosure are directed to expandable apparatus. By way of example and not limitation, an expandable apparatus may comprise an expandable reamer apparatus, an expandable stabilizer apparatus or similar apparatus. FIG. **1** illustrates an expandable apparatus **100** according to an embodiment of the disclosure comprising an expandable reamer. The expandable reamer may be similar to the expandable apparatus described in U.S. Patent Publication No. 2008/0128175, now U.S. Pat. No. 7,900,717, issued Mar. 8, 2011, the entire disclosure of which is incorporated herein by this reference.

The expandable apparatus **100** may include a generally cylindrical tubular body **105** having a longitudinal axis L_8. The tubular body **105** of the expandable apparatus **100** may have a lower end **110** and an upper end **115**. The terms "lower" and "upper," as used herein with reference to the ends **110**, **115**, refer to the typical positions of the ends **110**, **115** relative to one another when the expandable apparatus **100** is positioned within a wellbore. The lower end **110** of the tubular body **105** of the expandable apparatus **100** may include a set of threads (e.g., a threaded male pin member) for connecting the lower end **110** to another section of a drill string or another component of a bottom hole assembly (BHA), such as, for example, a drill collar or collars carrying a pilot drill bit for drilling a wellbore. Similarly, the upper end **115** of the tubular body **105** of the expandable apparatus **100** may include a set of threads (e.g., a threaded female box member) for connecting the upper end **115** to another section of a drill string or another component of a bottom hole assembly (BHA) (e.g., an upper sub).

At least one expandable feature may be positioned along the expandable apparatus **100**. For example, three expandable features configured as sliding cutter blocks or blades **120**, **125**, **130** (see FIG. **2**) are positionally retained in circumferentially spaced relationship in the tubular body **105** as further described below and may be provided at a position along the expandable apparatus **100** intermediate the lower end **110** and the upper end **115**. The blades **120**, **125**, **130** may be comprised of steel, tungsten carbide, a particle-matrix composite material (e.g., hard particles dispersed throughout a metal matrix material), or other suitable materials as known in the art. The blades **120**, **125**, **130** are retained in an initial, retracted position within the tubular body **105** of the expandable apparatus **100** as illustrated in FIG. **4**, but may be moved responsive to application of hydraulic pressure into the extended position (shown in FIG. **5**) and moved into a retracted position (shown in FIG. **4**) when desired, as will be described herein. The expandable apparatus **100** may be configured such that the blades **120**, **125**, **130** engage the walls of a subterranean formation surrounding a wellbore in which apparatus **100** is disposed to remove formation material when the blades **120**, **125**, **130** are in the extended position, but are not operable to so engage the walls of a subterranean formation within a wellbore when the blades **120**, **125**, **130** are in the retracted position. While the expandable apparatus **100** includes three blades **120**, **125**, **130**, it is contemplated that one, two or more than three blades may be utilized to advantage. Moreover, while the blades **120**, **125**, **130** are symmetrically circumferentially positioned axially along the tubular body **105**, the blades may also be positioned circumferentially asymmetrically as well as asymmetrically along the longitudinal axis L_8 in the direction of either end **110** or **115**.

The expandable apparatus **100** may optionally include a plurality of stabilizer blocks **135**, **140** and **145**. In some embodiments, the mid stabilizer block **140** and the lower stabilizer block **145** may be combined into a unitary stabilizer block. The stabilizer blocks **135**, **140**, **145** help to center the expandable apparatus **100** in the drill hole while being run into position through a casing or liner string and also while drilling and reaming the borehole. In other embodiments, no stabilizer blocks may be employed. In such embodiments, the tubular body **105** may comprise a larger outer diameter in the longitudinal portion where the stabilizer blocks are shown in FIG. **1** to provide a similar centering function as provided by the stabilizer blocks.

The upper stabilizer block **135** may be used to stop or limit the forward motion of the blades **120**, **125**, **130** (see also FIG. **3**), determining the extent to which the blades **120**, **125**, **130** may engage a borehole while drilling. The upper stabilizer block **135**, in addition to providing a back stop for limiting the lateral extent of the blades when extended, may provide for additional stability when the blades **120**, **125**, **130** are retracted and the expandable apparatus **100** of a drill string is positioned within a borehole in an area where an expanded hole is not desired while the drill string is rotating. Advantageously, the upper stabilizer block **135** may be mounted, removed and/or replaced by a technician, particularly in the field, allowing the extent to which the blades **120**, **125**, **130** engage the borehole to be readily increased or decreased to a different extent than illustrated. Optionally, it is recognized that a stop associated on a track side of the upper stabilizer block **135** may be customized in order to arrest the extent to which the blades **120**, **125**, **130** may laterally extend when fully positioned to the extended position along blade tracks **220**. The stabilizer blocks **135**, **140**, **145** may include hard-faced bearing pads (not shown) to provide a surface for contacting a wall of a borehole while stabilizing the expandable apparatus **100** therein during a drilling operation.

FIG. **2** is a cross-sectional view of the expandable apparatus **100** shown in FIG. **1** taken along section line **2-2** shown therein. As shown in FIG. **2**, the tubular body **105** encloses a fluid passageway **205** that extends longitudinally through the tubular body **105**. The fluid passageway **205** directs fluid substantially through an inner bore **210** of a stationary sleeve **215**. To better describe aspects of the invention, blades **125** and **130** are shown in FIG. **2** in the initial or retracted positions, while blade **120** is shown in the outward or extended position. The expandable apparatus **100** may be configured such that the outermost radial or lateral extent of each of the blades **120**, **125**, **130** is recessed within the tubular body **105** when in the initial or retracted positions so it may not extend beyond the greatest extent of outer diameter of the tubular body **105**. Such an arrangement may protect the blades **120**, **125**, **130**, a casing, or both, as the expandable apparatus **100** is disposed within the casing of a borehole, and may allow the expandable apparatus **100** to pass through such casing within a borehole. In other embodiments, the outermost radial extent of the blades **120**, **125**, **130** may coincide with or slightly extend beyond the outer diameter of the tubular body **105**. As illustrated by blade **120**, the blades **120**, **125**, **130** may extend

beyond the outer diameter of the tubular body **105** when in the extended position, to engage the walls of a borehole in a reaming operation.

FIG. **3** is another cross-sectional view of the expandable apparatus **100** shown in FIGS. **1** and **2** taken along section line **3-3** shown in FIG. **2**. Referring to FIGS. **2** and **3**, the tubular body **105** positionally retains three sliding cutter blocks or blades **120**, **125**, **130** in three respective blade tracks **220**. The blades **120**, **125**, **130** each carry a plurality of cutting elements **225** for engaging the material of a subterranean formation defining the wall of an open borehole when the blades **120**, **125**, **130** are in an extended position. The cutting elements **225** may be polycrystalline diamond compact (PDC) cutters or other cutting elements known to a person of ordinary skill in the art and as generally described in U.S. Pat. No. 7,036, 611, the disclosure of which is incorporated herein in its entirety by this reference.

Referring to FIG. **3**, the blades **120**, **125**, **130** (as illustrated by blade **120**) are hingedly coupled to a push sleeve **305**. The push sleeve **305** is disposed encircling the stationary sleeve **215** and configured to slide axially within the tubular body **105** in response to pressures applied to one end or the other, or both. In some embodiments, the push sleeve **305** may be disposed in the tubular body **105** and may be configured similar to the push sleeve described by U.S. Patent Publication No. 2008/0128175, now U.S. Pat. No. 7,900,717, issued Mar. 8, 2011, referenced above and biased by a spring as described therein.

In other embodiments, the push sleeve **305** may comprise an upper surface **310** and a lower surface **315** at opposing longitudinal ends. Such a push sleeve **305** may be configured and positioned so that the upper surface **310** comprises a smaller annular surface area than the lower surface **315** to create a greater force on the lower surface **315** than on the upper surface **310** when a like pressure is exerted on both surfaces by a pressurized fluid, as described in more detail below.

The stationary sleeve **215** comprises at least two fluid ports **320'** and **320"** and generally referred to collectively as fluid ports **320**, axially separated by a necked down orifice **325** proximate an upper end of the stationary sleeve **215**. The fluid ports **320** are positioned in communication with an upper annular chamber **330** located between an inner sidewall of the tubular body **105** and the outer surfaces of the stationary sleeve **215**, and in communication with the upper surface **310** of the push sleeve **305**. The stationary sleeve **215** may further include a plurality of nozzle ports **335** that may selectively communicate with a plurality of nozzles (not shown) for directing a drilling fluid toward the blades **120**, **125**, **130** when the blades are extended. A valve **340** is coupled to the lower end of the stationary sleeve **215** to selectively control the flow of fluid from the fluid passageway **205** to a lower annular chamber **345** between the inner sidewall of the tubular body **105** and the outer surfaces of the stationary sleeve **215**, and in communication with the lower surface **315** of the push sleeve **305**.

In operation, the push sleeve **305** is originally positioned toward the lower end **110** with the valve **340** closed, as shown in FIG. **4**. A fluid, such as a drilling fluid, may be flowed through the fluid passageway **205** in the direction of arrow **405**. Some of the fluid flowing through the fluid passageway **205** of the stationary sleeve **215** also flows through an upper fluid port **320'** into the upper annular chamber **330**. The pressure causing the fluid to flow through the fluid passageway **205** and into the upper annular chamber **330** exerts a force on the upper surface **310** of the push sleeve **305**, driving the push sleeve **305** toward the lower end **110**. When the push sleeve **305** is driven to the axially lower limit of its path of travel, the blades **120**, **125**, **130** (as illustrated by blade **120**) are fully retracted.

When the valve **340** is selectively opened, as will be described in greater detail below, the fluid also flows from the fluid passageway **205** into the lower annular chamber **345**, causing the fluid to pressurize the lower annular chamber **330**, exerting a force on the lower surface **315** of the push sleeve **305**. As described above, the lower surface **315** of the push sleeve **305** has a larger surface area than the upper surface **310**. Therefore, with equal or substantially equal pressures applied to the upper surface **310** and lower surface **315** by the fluid, the force applied on the lower surface **315**, having the larger surface area, will be greater than the force applied on the upper surface **310**, having the smaller surface area, by virtue of the fact that force is equal to the pressure applied multiplied by the area to which it is applied. The resultant net force is upward, causing the push sleeve **305** to slide upward, and extending the blades **120**, **125**, **130**, as shown in FIG. **5**. By way of example and not limitation, in an embodiment in which the difference in pressure between inside the expandable apparatus **100** and outside the expandable apparatus **100** is about 1,000 (one thousand) psi (about 6.894 MPa) and the difference between surface area of the upper surface **310** and the surface area of the lower surface **315** is about 14 in^2 (about 90 cm^2), the net upward force would be about 14,000 (fourteen thousand) lbs (about 62.275 kN).

When it is desired to retract the blades **120**, **125**, **130**, the valve **340** is closed to inhibit the fluid from flowing into the lower annular chamber **345** and applying a pressure on the lower surface **315** of the push sleeve **305**. When the valve **340** is closed, a volume of drilling fluid will remain trapped in the lower annular chamber **345**. At least one pressure relief nozzle **350** may accordingly be provided, extending through the sidewall of the tubular body **105** to allow the drilling fluid to escape from the lower annular chamber **345** and into an area between the borehole wall and the expandable apparatus **100** when the valve **340** is closed. The one or more pressure relief nozzles **350** may comprise a relatively small flow path so that a significant amount of pressure is not lost when the valve **340** is opened and the drilling fluid fills the lower annular chamber **345**. By way of example and not limitation, at least one embodiment of the pressure relief nozzle **350** may comprise a flow path of about 0.125 inch (about 3.175 mm) in diameter. In addition to the one or more pressure relief nozzles **350**, at least one high pressure release device **355** may be provided to provide pressure release should the pressure relief nozzle **350** fail (e.g., become plugged). The at least one high pressure release device **355** may comprise, for example, a backup burst disk, a high pressure check valve, or other device. In at least some embodiments, a screen (not shown) may be positioned over the at least one pressure relief nozzle **350** and the at least one high pressure release device **355** on both sides of the sidewall of tubular body **105** to inhibit the flow of materials that may plug at least one pressure relief nozzle **350** and the at least one high pressure release device **355**.

In the non-limiting example set forth above in which the difference in pressure between inside the expandable apparatus **100** and outside the expandable apparatus **100** is about 1,000 (one thousand) psi (about 6.894 MPa) and the surface area of the upper surface **310** is about 3 in^2 (about 19.3 cm^2), the net downward force would be about 3,000 (three thousand) lbs (about 13.345 kN) to bias the push sleeve **305** downward.

As stated above, the stationary sleeve **215** includes a necked down orifice **325** near the upper portion thereof

between the upper fluid port **320'** and the lower fluid port **320"**. The necked down orifice **325** comprises a portion of the stationary sleeve **215** in which the diameter of the inner bore **210** is reduced. By reducing the diameter through which the drilling fluid may flow, the necked down orifice **325** creates an increased pressure upstream from the necked down orifice **325**. The increased pressure above the necked down orifice **325** is typically monitored by conventional devices and this monitored pressure is conventionally referred to as the "monitored standpipe pressure."

In at least some embodiments, when the push sleeve **305** is positioned at the axially lower limit of its path of travel and the blades **120**, **125**, **130** are fully retracted, the upper fluid port **320'** is exposed to the upper annular chamber **330**, but the lower fluid port **320"** is at least substantially closed by the sidewall of the push sleeve **305**. Similarly, nozzle ports **335** may be closed by the sidewall of the push sleeve **305** since the blades **120**, **125**, **130** are not engaging the borehole and do not need to be cleaned and cooled and no cuttings need to be washed to the surface of the borehole. When the push sleeve **305** is repositioned to the axially upper limit of its path of travel so the blades **120**, **125**, **130** are fully extended, the upper fluid port **320'**, the lower fluid port **320"** and the nozzle ports **335** are all aligned with one or more openings (not shown) in the sidewall of push sleeve **305** so that fluid may flow through these ports **320'**, **320"**, **335**.

The fluid flowing through the nozzle ports **335** is directed to one or more nozzles (not shown) to cool and clean the blades **120**, **125**, **130**. With both the fluid ports **320** open to the upper annular chamber **330**, the fluid exits the upper fluid port **320'** above the necked down orifice **325**, into the upper annular chamber **330** and then back into the fluid passageway **205** through the lower fluid port **320"** below the necked down orifice **325**. This increases the total flow area through which the drilling fluid may flow (e.g., through the necked down orifice **325** and through the upper annular chamber **330** by means of the fluid ports **320**. The increase in the total flow area results in a substantial reduction in fluid pressure above the necked down orifice **325**. This decrease in pressure may be detected by an operator and identified in data comprising the monitored standpipe pressure, and may indicate to the operator that the blades **120**, **125**, **130** of the expandable apparatus **100** are in the expanded position. In other words, the decrease in pressure may provide a signal to the operator that the blades **120**, **125**, **130** have been expanded for engaging the borehole.

In at least some embodiments, the pressure drop may be between about 140 psi and about 270 psi. In one non-limiting example, the stationary sleeve **215** may comprise an inner bore of about 2.25 inches (about 57.2 mm) and the fluid ports **320** may be about 2 inches (50.8 mm) long and about 1 inch (25.4 mm) wide. In such an embodiment, a necked down orifice **325** comprising an inner diameter of about 1.625 inches (about 41.275 mm) will result in a drop in the monitored standpipe pressure of about 140 psi (about 965 kPa), assuming there are no nozzles, (the nozzles being optional according to various embodiments). In another example of such an embodiment, a necked down orifice **325** comprising an inner diameter of about 1.4 inches (about 35.56 mm) will result in a drop in the monitored standpipe pressure of about 269 psi (about 1.855 MPa).

Various embodiments of the present disclosure may employ mechanically actuated or controlled valves **340** or electronically actuated or controlled valves **340**. FIG. **6** illustrates an embodiment comprising a mechanically operated valve **340**. The mechanically operated valve **340** comprises a valve configured to open or to close in response to one or more mechanical forces. For example, in at least one embodiment, the valve **340** may comprise a valve sleeve **605** disposed within the tubular body **105** and coupled to a lower end of the stationary sleeve **215**. A valve cylinder **610** is disposed within the valve sleeve **605** and configured to selectively expose one or more valve ports **620**, through which a fluid may flow between the fluid passageway **205** and the lower annular chamber **345**.

With continued reference to FIG. **6**, FIG. **7** illustrates at least one embodiment of a valve cylinder **610** configured to be coupled with the valve sleeve **605** with a pin and pin track configuration. For example, the valve cylinder **610** may comprise a pin track formed in an outer surface thereof and configured to receive one or more pins on an inner surface of the valve sleeve **605**. In other embodiments, the valve cylinder **610** may comprise one or more pins on the outer surface thereof and the valve sleeve **605** may comprise a pin track formed in an inner surface for receiving the one or more pins of the valve cylinder **610**. FIG. **7** illustrates a valve cylinder **610** comprising a pin track **705** formed in an outer surface **710** according to one embodiment in which the pin track **705** comprises a J-slot configuration.

In operation, the valve cylinder **610** may be biased by a spring **615** exerting a force in the upward direction. The valve cylinder **610** may be configured with at least a portion having a reduced inner diameter, providing a constriction to downward flow of drilling fluid. When a drilling fluid flows through the valve cylinder **610** and the reduced inner diameter thereof, the pressure above the constriction created by the reduced inner diameter may be sufficient to overcome the upward force exerted by the spring **615**, causing the valve cylinder **610** to bias downward and the spring **615** to compress. If the flow of drilling fluid is eliminated or reduced below a selected threshold, the upward force exerted by the spring **615** may be sufficient to bias the valve cylinder **610** at least partially upward.

Referring to FIGS. **6** and **7**, one or more pins, such as pin **715** shown in dotted lines and carried by valve sleeve **605**, is received by the pin track **705**. Valve cylinder **610** is longitudinally and rotationally guided by the engagement of one or more pins **715** with pin track **705** when the cylinder **610** is biased downward and upward. For example, when there is relatively little or no fluid flow through the valve cylinder **610**, the force exerted by the spring **615** biases the valve cylinder **610** upward and the pin **715** rests in a first lower hooked portion **717** of the pin track **705**, as shown at the rightmost side of FIG. **7**. When drilling fluid is flowed through the valve cylinder **610** at a sufficient flow rate to overcome the force exerted by spring **615** and the valve cylinder **610** is biased downward, the track **705** moves along pin **715** until pin **715** comes into contact with an upper angled sidewall **720** of the pin track **705**. Movement of the valve cylinder **610** continues as pin **715** is engaged by the upper angled sidewall **720** until the pin **715** sits in a first upper hooked portion **725**. As the track **705** and its upper angled sidewall **720** is engaged by pin **715**, the valve cylinder **610** is forced to rotate, assuming the valve sleeve **605** to which the pin **715** is attached is fixed within the tubular body **105**. The rotation of the valve cylinder **610** may cause one or more apertures **730** in the valve cylinder **610** to move out of alignment with one or more valve ports **620** in communication with the lower annular chamber **345**, inhibiting flow of the drilling fluid from inside the valve **340** to the lower annular chamber **345**.

In order to open the valve **340**, according to the embodiment of FIG. **7**, the drilling fluid pressure may be reduced or eliminated, causing the valve cylinder **610** to bias upward in response to the force of the spring **615**. As the valve cylinder **610** is biased upward, it moves relative to the pin **715** carried

by the valve sleeve **605** until the pin **715** comes into contact with a lower angled sidewall **735** of the pin track **705**. The lower angled sidewall **735** continues to move along the pin **715** until the pin **715** sits in a second lower hooked portion **740**. As the lower angled sidewall **735** of the pin track **705** moves along the pin **715**, the valve cylinder **610** is again forced to rotate. When the drilling fluid is again flowed and the fluid pressure is again increased, the valve cylinder **610** biases downward and the track **705** moves along the pin **715** until the pin **715** comes into contact with an upper angled sidewall **745** of the track **705**. The upper angled sidewall **745** of track **705** moves along the pin **715** until the pin **715** sits in a second upper hooked portion **750**, which is shown by dotted lines. As the upper angled sidewall **745** of the pin track **705** moves with respect to pin **715**, the valve cylinder **610** is forced to rotate still further within the valve sleeve **605**. This rotation may cause the one or more apertures **730** to rotationally align with the one or more valve ports **620** carried by valve sleeve **605**, allowing drilling fluid to flow into the lower annular chamber **345** and sliding the push sleeve **305** as described above.

In another embodiment, the valve cylinder **610** may have no apertures **730** or may have one or more apertures **730** which require both rotational and longitudinal displacement of valve cylinder **610** to open flow to one or more valve ports **620**, and may be configured so that every other upper (or lower, as desired) hooked portion is configured to allow the valve cylinder **610**, guided by engagement of pin track **705** with pin **715**, to travel to a higher (or lower) respective position (as oriented in use) than the respective position allowed by the intermediate upper (or lower) hooked portions. For example, the second upper hooked portion **750** may be located at a respectively higher location than the first upper hooked portion **725**, permitting greater longitudinal displacement of valve cylinder **610** with respect to valve sleeve **605**, and permitting communication of one or more valve ports **620** with the interior of valve cylinder **610** when valve cylinder **610** is either at its higher or lower position, as desired. In other embodiments, as shown in FIG. **7**, the second upper hooked portion **750** may be replaced by an elongated slotted portion **755**. In either embodiment, the valve cylinder **610** can travel to a significantly more extended longitudinal location along valve sleeve **605** when a selected portion of pin track **705** is engaged with pin **715**. In such embodiments, instead of aligning an aperture with the valve port **620**, the valve cylinder **610** can be displaced downward by the flowing drilling fluid, or upward by spring **615**, a sufficient longitudinal distance to expose the one or more valve ports **620**.

It will be apparent that the valve **340** as embodied according to any of the various embodiments described above may be opened and closed repeatedly by simply reducing the flow rate of the drilling fluid and again increasing the flow rate of the drilling fluid to cause the valve cylinder **610** to bias upward and downward, resulting in the rotational and axial displacement described above due to the pin and track arrangement. By way of example and not limitation, the valve **340** embodied as described above may be configured with a bore size and spring force so that a flow rate of about 400 gpm (about 1,514 lpm) or higher may be sufficient to adequately bias the valve cylinder **610** downward against the spring **615**, while a flow rate of about 100 gpm (about 378 lpm) or lower may be sufficient to allow the spring **615** to bias the valve cylinder **610** upward.

In still another embodiment of the mechanically operated valve **340**, the valve cylinder **610** may comprise an inner diameter configuration substantially similar to the valve cylinder **610** shown in FIG. **6**, and may also comprise a substantially cylindrical outer surface configured to abut against an inner sidewall of the valve sleeve **605**. However, no pin and track arrangement is employed. Such embodiments are configured to inhibit drilling fluid flow into the valve port **620** by simply covering the valve port **620** whenever the pressure of the drilling fluid is insufficient to axially displace the valve cylinder **610** against the force of the spring **615** an adequate distance to expose the valve port **620**. To open this embodiment of the valve **340**, the drilling fluid flow rate is increased to sufficiently displace the valve cylinder **610** so the valve port **620** is exposed and drilling fluid can flow through valve port **620** into, and pressurize, the lower annular chamber **345**. Similar to the embodiments of the valve **340** described previously, the valve cylinder **610** may be opened and closed repeatedly by simply increasing and decreasing the flow rate of the drilling fluid.

FIG. **8** illustrates an embodiment of the expandable apparatus **100** comprising an electronically operated valve **340'**. In various embodiments, the electronically operated valve **340'** comprises a valve sleeve **805** comprising at least one valve **810** associated with a valve port **815** in communication with the lower annular chamber **345**. The valve **810** is controllably opened and closed by a drive device **820**. By way of example and not limitation, the drive device **820** may comprise a solenoid, an electric motor such as a servo motor, or any other known device suitable for controlling the orientation or location of the valve **810**. In order to reduce power consumption, valve **810** associated with valve port **815** may comprise, for example, a small pilot valve which is selectively caused by drive device **820** to direct drilling fluid pressure through a pilot port to open another larger valve **815** which may be, for example a spring-biased valve, to permit drilling fluid flow into lower annular chamber **345** through larger valve port **815**. The drive device **820** is operably coupled to a controller **825**. The controller **825** may be positioned in any location where it can readily control the operation of the actuation device **820**. For example, FIG. **8** shows three non-limiting embodiments of the controller **825**, such as controller **825** configured to be positioned in a sidewall of the tubular body **105**, controller **825'** configured to be positioned within the valve sleeve **805**, and controller **825"** comprising a probe configuration to be positioned in the fluid passageway **205** adjacent to the valve sleeve **805**. As used herein, reference to "the controller **825**" is intended to refer to any of the above described embodiments including controllers **825**, **825'** and **825"**. Of course, components of the controller may be distributed among multiple locations and operably coupled.

The controller **825** may comprise processing circuitry configured to obtain data, process data, send data, and combinations thereof. The processing circuitry may also control data access and storage, issue commands, and control other desired operations. The controller **825** may further include storage media coupled to the processing circuitry and configured to store executable code or instructions (e.g., software, firmware, or combinations thereof), electronic data, databases or other digital information and may include processor-usable media. The controller **825** may include a battery for providing electrical power to the various components thereof, including the drive device **820**. The controller **825** may also include, or be operably coupled to, an apparatus state detection device coupled to the processing circuitry and configured to detect one or more selected states of the expandable apparatus **100**. For example, the apparatus state detection device may comprise one or more accelerometers or magnetometers **850** configured to detect a rotational speed of the expandable

apparatus **100**, a rotational direction of the expandable apparatus **100**, or a combination of rotational speed and rotational direction.

The controller **825** may include programming configured to change the state of the valve **810** in response to some predetermined command signal provided by an operator. One non-limiting example of a command signal may comprise rotating the expandable apparatus **100** at a given rotational speed for a determined period of time, stopping the rotation and repeating the rotation and stopping for some given number of times (e.g., three times). Such a combination of rotation and stopping is detected by one or more accelerometers **850** which may, for example, if not incorporated in a controller **825**, may be placed in a separate compartment of tubular body **105**. The controller **825** operates to open or close the valve **810** based on the detection of this combination by the accelerometers. Another non-limiting example of a command signal may comprise rotating the expandable apparatus **100** at a rate of 60 rpm for 60 seconds, followed by a rate of 90 rpm for 90 seconds. One of ordinary skill in the art will recognize that a plurality of possible signals and signal types may be employed for activating the controller **825**.

As another approach to command signal detection, a removable module including accelerometers **850** and, optionally, other sensors such as magnetometers, may be placed in alignment with fluid passageway **205** at the upper end **115** or the lower end **110** of expandable apparatus **100** (see FIG. **3**), or in the wall or a bore of a sub secured to the upper end or lower end. Signals from such a module may be transmitted through wiring in the wall of tubular body **105** of expandable apparatus, or by so-called "short hop" wireless telemetry to a receiver associated in controller **825**. Such a module suitable for disposition in a tool bore may be configured in the form of an annular DATABIT™ module, offered by Baker Hughes Incorporated. The structure and operation of one embodiment of such a module is described in U.S. Pat. No. 7,604,072, issued Oct. 20, 2009 and assigned to the assignee of the present disclosure. The disclosure of the foregoing patent is hereby incorporated herein in its entirety by reference.

As a result of each of the foregoing embodiments and equivalents thereof, expandable apparatuses of various embodiments of the disclosure may be expanded and contracted by an operator an unlimited number of times.

FIG. **9** illustrates another embodiment of an expandable apparatus **100**. In the embodiment disclosed, the one or more valve ports **620** in the valve sleeve **605** are left unobstructed, allowing fluid to flow into the lower annular chamber **345**. The fluid flowing into the lower annular chamber **345** may exert a force on the lower surface **315** of the push sleeve **305**, causing the push sleeve **305** to slide upward and extending the blades **120**, **125**, **130** (as illustrated by blade **120**), as discussed previously. A screen catcher **955** is coupled to the valve sleeve **605** for catching discarded traps **905** (FIG. **10**) and balls **950** (FIG. **12**) as discussed in further detail below. The screen catcher **955** is configured to catch the traps **905** and balls **950** while having little to no effect on the flow of the drilling fluid therethrough. In some embodiments, the screen catcher **955** may include a removable cap (not shown) for removing traps **905** and balls **950** from the screen catcher **955** when the expandable apparatus **100** is no longer in use.

As shown in FIG. **10**, when it is desired to retract the blades **120**, **125**, **130**, drilling fluid flow is momentarily ceased, if required, and a trap **905** is dropped into the drill string and pumping of drilling fluid resumed. The trap **905** moves down the drill string and through the expandable reamer apparatus **100** toward the lower end **110**. After a short time, the trap **905** is latched in the valve sleeve **605** and obstructs the at least one fluid port **620**. FIG. **11** is an enlarged cross-sectional view of the lower end **110** of the expandable apparatus **100** shown in FIG. **10**. As shown in FIG. **11**, complementary positioning features may be provided in the trap **905** and the valve sleeve **605** to facilitate proper relative positioning therebetween when the trap **905** travels through the valve sleeve **605**. In some embodiments, as shown in FIG. **11**, the trap **905** may comprise a male connection feature, such as at least one protrusion **910** shaped as a radially extended flange extending circumferentially at least partially around a longitudinal axis of the trap **905**. In some embodiments, the trap **905** may comprise a solid tubular cylinder, or the tubular cylinder may be partially cut along a longitudinal axis of the trap at circumferential intervals to form individual, finger-like extensions each with a protrusion thereon. The valve sleeve **605** may comprise a female connection feature, such as an annular receptacle or recess **915** formed in a surface **920** of the valve sleeve **605**. The recess **915** may be a complementary size and shape to that of the at least one protrusion **910** and may be configured to receive the at least one protrusion **910** therein. The at least one protrusion **910** may comprise a malleable material, such as, for example brass, or may be resiliently biased outwardly. When inserting the trap **910** into the drill string, the at least one protrusion **910** may be retracted in toward the center of the fluid passageway **205**, or be resilient biased to easily contract, so that trap **905** can pass through the fluid passageway **205**. Once the protrusion **910** reaches the recess **915**, the at least one protrusion **910** will extend laterally outward into the recess **915** and latch the trap **905** into a desired location in the valve sleeve **605**. Fluid seals **925**, such as an o-ring, may be coupled to the trap **905** to further obstruct fluid from entering valve port **620**. The trap **905** may also include at least one protrusion **912**, which may be of annular configuration, extending into the fluid passageway **205**, which functions as a ball seat **930** and which will be discussed in further detail below.

Referring back to FIG. **10**, with the trap sleeve **905** latched in valve sleeve **605**, the drilling fluid will continue to flow through the upper fluid port **320'** into the upper annular chamber **330** but the fluid will be obstructed from flowing through the at least one valve port **620** into the lower annular chamber **345**. When the at least valve port **620** is obstructed by the trap **905**, a volume of drilling fluid will remain in the lower annular chamber **345**. The drilling fluid escapes from the lower annular chamber **345** through the pressure nozzle **350**, as previously discussed. As the fluid in the lower annular chamber **345** escapes, the force on the upper surface **310** of the push sleeve **305** caused by the fluid flow through the fluid passageway **205** into the upper annular chamber **330** will exceed the force on the lower surface **315** of the push sleeve **305**, driving the push sleeve **305** to the lower end **190** of the expandable apparatus **100**. When the push sleeve **305** is driven to the axially lower limit of its path of travel, the blades **120**, **125**, **130** are fully retracted.

As shown in FIGS. **12** and **13**, when it is desired to trigger the expandable apparatus **100** to re-extend the blades **120**, **125**, **130**, drilling fluid flow may be momentarily ceased, if required, and a ball **905** or other flow restricting element, is dropped into the drill string and pumping of drilling fluid resumed. The ball **950** moves toward the lower end **110** of the expandable reamer apparatus **100** under the influence of gravity, the flow of drilling fluid, or both, until the ball **950** reaches the ball seat **930** where the ball **950** becomes trapped. The ball **950** stops drilling fluid flow and causes pressure to build above it in the drill string. As the pressure builds, the protrusion or protrusions **910** of trap **905** may either shear off, or the protrusions **910** of the trap **905** may be deformed or biased

radially inwardly such that the protrusion or protrusions **910** are retracted inward away from the valve sleeve **605**. With the protrusions **910** sheared, deformed, or biased inwardly, the metal trap **905** and the ball **950** will be expelled from the valve sleeve **605** into the screen catcher **955** as shown in FIG. **13**. With the trap **905** and the ball **950** in the screen catcher **955**, the valve port **620** is again unobstructed, and fluid may flow through the valve port **620** into the lower annular chamber **345** and cause the blades **120**, **125**, **130** to extend as previously described regarding FIG. **9**. The process of retracting and extending the blades **120**, **125**, **130** described in FIGS. **9** through **13** may be repeated as desired until the screen catcher **955** cannot accept additional discarded traps **905** and balls **950**.

Although the foregoing disclosure illustrates embodiments of an expandable apparatus comprising an expandable reamer apparatus, the disclosure is not so limited. For example, in accordance with other embodiments of the disclosure, the expandable apparatus may comprise an expandable stabilizer, wherein the one or more expandable features may comprise stabilizer blocks (e.g., the blades **120**, **125**, **130** may be replaced with one or more stabilizer blocks).

FIG. **14** is a schematic diagram of an embodiment of a drilling system **1100** that includes a drill string having a drilling assembly attached to its bottom end that includes a steering unit according to one embodiment of the disclosure. FIG. **14** shows a drill string **1120** that includes a drilling assembly or bottom hole assembly ("BHA") **1190** conveyed in a borehole **1126**. The drilling system **1100** includes a conventional derrick **1111** erected on a platform or floor **1112** which supports a rotary table **1114** that is rotated by a prime mover, such as an electric motor (not shown), at a desired rotational speed. A tubular string (such as jointed drill pipe) **1122**, having the drilling assembly **1190** attached at its bottom end extends from the surface to a bottom **1151** of the borehole **1126**. A drill bit **1150**, attached to drilling assembly **1190**, disintegrates the geological formations when it is rotated to drill the borehole **1126**. The drill string **1120** is coupled to a draw works **1130** via a Kelly joint **1121**, swivel **1128** and line **1129** through a pulley. Draw works **1130** is operated to control the weight on bit ("WOB"). The drill string **1120** may be rotated by a top drive (not shown) instead of by the prime mover and the rotary table **1114**. The operation of the draw works **1130** is known in the art and is thus not described in detail herein.

In one aspect of operation, a suitable drilling fluid **1131** (also referred to as "mud") from a source **1132** thereof, such as a mud pit, is circulated under pressure through the drill string **1120** by a mud pump **1134**. The drilling fluid **1131** passes from the mud pump **1134** into the drill string **1120** via a de-surger **1136** and a fluid line **1138**. The drilling fluid **1131***a* from the drilling tubular discharges at the borehole bottom **1151** through openings in the drill bit **1150**. The returning drilling fluid **1131***b* circulates uphole through an annular space **1127** between the drill string **1120** and the borehole **1126** and returns to the mud pit **1132** via a return line **1135** and drill cuttings **1186** screen **1185** that removes drill cuttings **1186** from the returning drilling fluid **1131***b*. A sensor S_1 in line **1138** provides information about the fluid flow rate. A surface torque sensor S_2 and a sensor S_3 associated with the drill string **1120** provide information about the torque and the rotational speed of the drill string **1120**. Rate of penetration of the drill string **1120** may be determined from the sensor S_5, while the sensor S_6 may provide the hook load of the drill string **1120**.

In some applications, the drill bit **1150** is rotated by rotating the drill pipe **1122**. However, in other applications, a downhole motor **1155** such as, for example, a Moineau-type so-called "mud" motor or a turbine motor disposed in the drilling assembly **1190** may rotate the drill bit **1150**. In embodiments, the rotation of the drill string **1120** may be selectively powered by one or both of surface equipment and the downhole motor **1155**. The rate of penetration ("ROP") for a given drill bit and BHA largely depends on the WOB, or other thrust force, applied to the drill bit **1150** and its rotational speed.

With continued reference to FIG. **14**, a surface control unit or controller **1140** receives signals from the downhole sensors and devices via a sensor **1143** placed in the fluid line **1138** and signals from sensors S_1-S_6 and other sensors used in the system **1100** and processes such signals according to programmed instructions provided from a program to the surface control unit **1140**. The surface control unit **1140** displays desired drilling parameters and other information on a display/monitor **1142***a* that is utilized by an operator to control the drilling operations. The surface control unit **1140** may be a computer-based unit that may include a processor **1142** (such as a microprocessor), a storage device **1144**, such as a solid-state memory, tape or hard disc, and one or more computer programs **1146** in the storage device **1144** that are accessible to the processor **1142** for executing instructions contained in such programs. The surface control unit **1140** may further communicate with at least one remote control unit **1148** located at another surface location. The surface control unit **1140** may process data relating to the drilling operations, data from the sensors and devices on the surface, data received from downhole and may control one or more operations of the downhole and surface devices.

The drilling assembly **1190** also contains formation evaluation sensors or devices (also referred to as measurement-while-drilling, "MWD," or logging-while-drilling, "LWD," sensors) determining resistivity, density, porosity, permeability, acoustic properties, nuclear-magnetic resonance properties, corrosive properties of the fluids or formation downhole, salt or saline content, and other selected properties of a formation **1195** surrounding the drilling assembly **1190**. Such sensors are generally known in the art and for convenience are generally denoted herein by numeral **1165**. The drilling assembly **1190** may further include a variety of other sensors and communication devices **1159** for controlling and/or determining one or more functions and properties of the drilling assembly (such as velocity, vibration, bending moment, acceleration, oscillations, whirl, stick-slip, etc.) and drilling operating parameters, such as weight-on-bit, fluid flow rate, pressure, temperature, rate of penetration, azimuth, tool face, drill bit rotation, etc.

Still referring to FIG. **14**, the drill string **1120** further includes one or more downhole tools **1160***a* and **1160***b*. In an aspect, the tool **1160***a* is located in the BHA **1190**, and includes at least one reamer **1180***a* to enlarge the diameter of wellbore **1126** as the BHA **1190** penetrates the formation **1195**. In addition, the tool **1160***b* may be positioned uphole of and coupled to the BHA **1190**, wherein the tool **1160***b* includes a reamer **1180***b*. In one embodiment, each reamer **1180***a*, **1180***b*, which may comprise one or more circumferentially spaced blades or other elements carrying cutting structures thereon, is an expandable reamer that is selectively extended and retracted from the tool **1160***a*, **1160***b* to engage and disengage the wellbore wall. The reamers **1180***a*, **1180***b* may also stabilize the drilling assembly **1190** during downhole operations. In an aspect, the actuation or movement of the reamers **1180***a*, **1180***b* is powered by an actuation device **1182***a*, **1182***b*, respectively. The actuation devices **1182***a*, **1182***b* are in turn controlled by controllers **1184***a*, **1184***b*

positioned in or coupled to the actuation devices **1182***a*, **1182***b*. The controllers **1184***a*, **1184***b* may operate independently or may be in communication with other controllers, such as the surface controller **1140**. In one aspect, the surface controller **1140** remotely controls the actuation of the reamers **1180***a*, **1180***b* via downhole controllers **1184***a*, **1184***b*, respectively. The controllers **1184***a*, **1184***b* may be a computer-based unit that may include a processor, a storage device, such as a solid-state memory, tape or hard disc, and one or more computer programs in the storage device that are accessible to the processor for executing instructions contained in such programs. It should be noted that the depicted reamers **1180***a*, **1180***b* are only one example of a tool or apparatus that may be actuated or powered by the actuation devices **1182***a*, **1182***b*, which are described in detail below. In some embodiments, the drilling system **1100** may utilize the actuation devices **1182***a*, **1182***b* to actuate one or more tools, such as reamers, stabilizers with movable pads, steering pads and/or drilling bits with movable blades, by selectively flowing of a fluid. Accordingly, the actuation devices **1182***a*, **1182***b* provide actuation to one or more downhole apparatus or tools **1160***a*, **1160***b*, wherein the device is controlled remotely, at the surface, or locally by controllers **1184***a*, **1184***b*.

FIGS. **15**A and **15**B are sectional side views of an embodiment a portion of a drill string, a tool and an actuation device, wherein the tool is depicted in two positions. FIG. **15**A shows a tool **1200** with a reamer blade **1202** in a retracted, inactive or closed position. FIG. **2**B shows the tool **1200** with reamer blade **1202** in an extended or active position. The tool **1200** includes an actuation device **1204** configured to change positions, states or operational modes of the reamer **1202**. The depicted tool **1200** shows a single reamer blade **1202** and actuation device **1204**, however, the concepts discussed herein may apply to embodiments with a plurality of tools **1200**, reamers **1202** and/or actuation devices **1204**. For example, a single actuation device **1204** can actuate a plurality of reamer blades **1202** in a tool **1200**, wherein the actuation device **1204** controls fluid flow to the move the reamer blades **1202**. As shown, the actuation device **1204** is schematically depicted as a functional block; however, greater detail is shown in FIGS. **16**A and **16**B. In an aspect, the reamer blade **1202** includes or is coupled to an actuation assembly **1206**, wherein the actuation device **1204** and the actuation assembly **1206** causes movement of reamer blade **1202**. Line **1208** provides fluid communication between actuation device **1204** and the actuation assembly **1206**. The actuation assembly **1206** includes a chamber **1210**, sliding sleeve **1212**, bleed nozzle **1214** and check valve **1216**. The sliding sleeve **1212** (or annular piston) is coupled to the reamer blade **1202**, wherein the reamer blade **1202** may extend and retract along actuation track **1218**. In an aspect, the reamer blade **1202** includes abrasive members, such as cutters configured to remove formation material from a wellbore wall, thereby enlarging the diameter of the wellbore. The reamer blade **1202** may extend to contact a wellbore wall as shown by arrow **1219** and in FIG. **15**B.

Still referring to FIGS. **15**A and **15**B, in an aspect, drilling fluid **1224** flows through a sleeve **1220**, wherein the sleeve **1220** includes a flow orifice **1222**, flow bypass port **1226**, and nozzle ports **1228**. In one aspect, the actuation device **1204** is electronically coupled to a controller located uphole via a line **1230**. As described below, the actuation device **1204** may include a controller configured for local control of the device. Further, the actuation device **1204** may be coupled to other devices, sensors and/or controllers downhole, as shown by line **1232**. For example, tool end **1234** may be coupled to a BHA, wherein the line **1232** communicates with devices and sensors located in the BHA. As depicted, the line **1230** may be coupled to sensors that enable surface control of the actuation device **1204** via signals generated uphole that communicate commands including the desired position of the reamer **1202**. In one aspect, the line **1232** is coupled to accelerometers that detect patterns in the drill string rotation rate, or RPM, wherein the pattern is decoded for commands to control one or more actuation device **1204**. Further, an operator may use the line **1230** to alter the position based on a condition, such as drilling a deviated wellbore at a selected angle. For example, a signal from the surface controller may extend the reamer blade **1202**, as shown in FIG. **15**B, during drilling of a deviated wellbore at an angle of 15 degrees, wherein the extended reamer blade **1202** provides stability while also increasing the wellbore diameter. It should be noted that FIGS. **15**A and **15**B illustrate non-limiting examples of a tool or device (**1200**, **1202**) that may be controlled by fluid flow from the actuation device **1204**, which is also described in detail with reference to FIGS. **3**A and **3**B.

FIGS. **16**A and **16**B are schematic sectional side views of an embodiment of an actuation device **1300** in two positions. FIG. **16**A illustrates the actuation device **1300** in an active position, providing fluid flow **1301** to actuate a downhole tool, as described in FIGS. **15**A and **15**B. FIG. **16**B shows the actuation device **1300** in a closed position, where there is no fluid flow to actuate the tool. In an aspect, the actuation device **1300** includes a housing **1302** and a piston **1304** located in the housing **1302**. The housing **1302** includes a chamber **1306** where an annular member **1307**, extending radially from the piston **1304**, is positioned. In an aspect, the housing **1302** contains a hydraulic fluid **1308**, such as a substantially non-compressible oil. The chamber **1306** may be divided into two chambers, **1309***a* and **1309***b*, by the annular member **1307**. Further, the fluid **1308** may be transferred between the chambers **1309***a* and **1309***b* by a flow control device **1310** (or locking device), enabling movement of the annular member **1307** within chamber **1306**. In an aspect, the housing **1302** includes a port **1312** that provides fluid communication with the line **1208** (FIGS. **15**A and **15**B). When the piston **1304** is in a selected active axial position, as shown in FIG. **16**A, a port **1314** enables fluid communication from bore **1316** to port **1312** and line **1208**. In one aspect, a drilling fluid is pumped by surface pumps causing the fluid to flow downhole, shown by arrow **1317**. Accordingly, as depicted in FIG. **16**A, the actuation device **1300** is in an active position where drilling fluid flows from the bore **1316** through ports **1314**, **1312** and into a supply line **1208**, as shown by arrow **1301**. In an aspect, the actuation device **1300** includes a plurality of seals, such as ring seals **1315***a*, **1315***b*, **1315***c*, **1315***d* and **1315***e*, where the seals restrict and enable fluid flow through selected portions of the device **1300**. As depicted, the flow control device **1310** (also referred to as a "locking device") uses enabling or stopping a flow of fluid to selectively "lock" the piston **1304** in a selected axial position. It should be understood that any suitable locking device may be used to control axial movement by locking and unlocking the position of annular member **1307** within chamber **1306**. In other aspects, the locking device **1310** may comprise any suitable mechanical, hydraulic or electric components, such as a solenoid or a biased collet.

With continued reference to FIGS. **16**A and **16**B, a biasing member **1320**, such as a spring, is operably positioned between the housing **1302** and a flange of piston **1304**. The biasing member **1320** may be axially compressed and extended, thereby providing an axial force as the piston **1304** moves along axis **1321**. In an aspect, the flow control device

1310 is used to control axial movement of the piston **1304** within the housing **1302**. As depicted, the flow control device **1310** is a closed loop hydraulic system that includes a hydraulic line **1322**, a valve **1324**, a processor **1326** and a memory device **1328**, wherein one or more software programs **1329** are configured to run on the processor **1326** and memory device **1328**. The processor **1326** may be a microprocessor configured to control the opening and closing of valve **1324**, which is in fluid communication with chambers **1309***a*, **1309***b*. In an embodiment, the processor **1326** and memory **1328** are connected by a line **1330** to other devices uphole, such as a controller or sensors in the drill string. In other embodiments, the flow control device **1310** operates independently or locally, based on the control of the processor **1326**, memory **1328**, software programs **1329** and additional inputs, such as sensed downhole parameters and patterns within sensed parameters. In another aspect, the flow control device **1310** and actuation device **1300** may be controlled by a surface controller, where signals are sent downhole by a communication line, such as line **1330**. In another aspect, a sensor, such as an accelerometer, may sense a pattern in mud pulses, wherein the pattern communicates a command message, such as one describing a desired position for the actuation device **1300**. As depicted, the piston **1304** includes a nozzle **1335** with one or more bypass ports **1336**, where the nozzle **1335** enables flow from the bore **316** downhole.

The operation of actuation device **1300**, with reference to FIGS. **16**A and **16**B, is discussed in detail below. FIG. **16**A shows the actuation device **1300** in an active position. The device **1300** moves to an active position when drilling fluid flowing downhole **1317** through the restriction provided by nozzle **1335** causes an axial force in the flow direction, pushing the piston **1304** axially **1333**. In an embodiment, the fluid flow axial force is greater than the resisting spring force of biasing member **1320**, thereby compressing the biasing member **1320** as the piston **1304** moves in direction **1333**. In addition, the valve **1324** is opened to allow hydraulic fluid to flow from chamber **1309***b*, substantially filling chamber **1309***a*. This enables movement of annular member **1307** in chamber **1306**, thereby enabling the piston **1304** to move axially **1333**. Accordingly, as the valve **1324** is opened (or unlocked) the flow of drilling fluid downhole **1317**, controlled uphole by mud pumps, provides an axial force to move piston **1304** to the active position. As the chamber **1309***a* is substantially full and chamber **1309***b* is substantially empty, the valve **1324** is closed or locked, thereby enabling the ports **1312** and **1314**, which are aligned and provide a flow path, to be locked in an aligned arrangement. In the active position, the drilling fluid flows in a substantially unrestricted manner through the nozzle **1335** and bypass ports **1336**, as flow from the bypass ports **1336** is not restricted by inner surface **1338**. Accordingly, in the active position, the actuation device **1300** provides fluid flow **1301** to actuate one or more downhole tools, such as reamer **1202** shown in FIG. **15**B.

As shown in FIG. **16**B, the actuation device **1300** is in a closed position, where the piston **1304** has been moved axially **1332** by the flow control device **1310** and biasing member **1320**, thereby stopping a flow of drilling fluid from the annulus **1316** through ports **1314** and **1312**. To move actuation device **1300** to the closed position, the valve **1324** is opened to enable hydraulic fluid to flow from chamber **1309***a* to chamber **1309***b*, thereby unlocking the position of annular member **1307** within chamber **1306** and enabling the piston **1304** to move axially **1332**. In addition, the flow of drilling fluid downhole **1317** is reduced or stopped to allow the force of biasing member **1320** to cause piston **1304** to move axially uphole **1332**. Once the piston **1304** is in the desired closed position, where the ports **1312** and **1314** are not in fluid communication with each other, the valve **1324** is closed to lock the piston **1304** in place and preclude fluid communication through ports **1312** and **1314**. In the closed position, the chamber **1309***a* is substantially empty and the chamber **1309***b* is substantially full. In addition, in the closed position of actuation device **1300**, drilling fluid does not flow through the bypass ports **1336**, which are restricted by surrounding inner surface **1338**. Thus, the actuation device **1300** in a closed position shuts off fluid flow and corresponding actuation to one or more tools operationally coupled to the device, thereby keeping the tool, such as a reamer blade **1202** (FIG. **15**A) in a neutral position. It should be noted that a difference in drilling fluid back pressure as it flows through actuation device **1300**, due to the obstruction or non-obstruction of bypass ports **1336** and the lack or presence of fluid flow through ports **1312** and **1314**, may be used by an operator at the surface to verify the operational mode of the apparatus in which actuation device **1300** is employed.

Referring back to FIG. **14**, in an aspect, one or more downhole devices or tools, such as the reamers **1180***a*, **1180***b*, are controlled by and communicate with the surface via pattern recognition signals transmitted through the drill string. The signal patterns may be any suitable robust signal that allows communication between the surface drilling rig and the downhole tool, such as changes in drill string rotation rate (revolutions per minute or "RPM") or changes in mud pulse frequency. In an aspect, the sequence, rotation rate speed (RPM) and duration of the rotation is considered a pattern or pattern command that is detected downhole to control one or more downhole tools. For example, the drill string may be rotated by the drilling rig at 40 RPM for 10 seconds, followed by a rotation of 20 RPM for 30 seconds, where one or more sensors, such as accelerometers or other sensors, sense the drill string rotation speed and route such detected speeds and corresponding signals to a processor **1326** (FIGS. **16**A and **16**B). Another suitable rotational sequence is, for example, a three-signal pattern of 30 rpm for 30 seconds, then 60 rpm for 20 second, then 10 rpm for 60 seconds. The processor **1326** decodes the pattern of rotational speeds and durations by comparison to patterns stored in memory **1328** to determine the selected tool position sent from the surface and then the actuation device **1300** (FIGS. **16**A and **16**B) causes the tool to move to the desired position. In another aspect, a sequence of mud pulses of a varying parameter, such as duration, amplitude and/or frequency may provide a command pattern received by pressure sensors to control one or more downhole devices. In aspects, a plurality of downhole tools may be controlled by pattern commands, wherein a first pattern sequence triggers a first tool to position A and a second pattern sequence triggers a second tool to second position B. In the example, the first and second patterns may be RPM and/or pulse patterns that communicate specific commands to two separate tools downhole. Thus, RPM pattern sequences and/or pulse pattern sequences in combination with a tool and actuation device, such as the actuation device described above, and sensors enable communication with and improved control of one or more downhole devices.

As yet another actuation device command signal alternative, rather than using drill string rotation or mud pulses, a series of different drilling fluid flow rates and durations may be used as patterns for detection by a downhole flow meter, which may be used to provide a pattern of signals to processor **1326**. One example flow rate signal pattern may be characterized as 50 gpm for 20 seconds, then 100 gpm for 30 seconds, then zero flow for 30 seconds.

A further actuation device command signal alternative using flow detection by a flow meter may employ engagement of a drilling fluid (mud) pump for 30 seconds, followed by shut off for 30 seconds, followed by pump engagement for 45 seconds, followed by shut down.

Yet another actuation device command signal alternative using accelerometers for drill string motion detection may include axial motion of the drill string in combination with rotation. For example, the drill string may be lifted quickly by three feet (0.91 meter), dropped by two feet (0.60 meter), then rotated at 30 rpm for 30 seconds, and stopped for 30 seconds.

In all of the foregoing embodiments where command signals generated by detection of one or more of rotational drill string movement, axial drill string movement, drilling fluid pressure, and drilling fluid and/or flow rate in various combinations, including combinations with time periods, are employed, the reference numerals **850** in the drawing figures are indicative of non-limiting examples of suitable locations, and presence of, sensors for detection of such parameters and circuitry for generation of command signals therefrom.

Thus, while certain embodiments have been described and shown in the accompanying drawings, such embodiments are merely illustrative and not restrictive of the scope of the invention, and this invention is not limited to the specific constructions and arrangements shown and described, since various other additions and modifications to, and deletions from, the described embodiments will be apparent to one of ordinary skill in the art. The scope of the invention is, accordingly, limited only by the claims that follow herein, and legal equivalents thereof.

What is claimed is:

1. An expandable apparatus, comprising:

a tubular body comprising a fluid passageway extending through an inner bore;

a push sleeve disposed within the inner bore of the tubular body and coupled to one or more expandable features, the push sleeve comprising an upper annular end surface in communication with an upper annular chamber between the push sleeve and the tubular body separate from the fluid passageway and a lower annular end surface in communication with a lower annular chamber between the push sleeve and the tubular body separate from the fluid passageway, wherein the lower annular end surface has a larger surface area than the upper annular end surface, the push sleeve configured to move axially responsive to a flow of drilling fluid through the fluid passageway and into the lower annular chamber to extend the one or more expandable features; and

a valve within the tubular body configured to selectively control the flow of drilling fluid from the fluid passageway into the lower annular chamber.

2. The expandable apparatus of claim **1**, wherein the upper annular end surface of the push sleeve is exposed to the flow of drilling fluid in the upper annular chamber whenever a drilling fluid is introduced into the fluid passageway.

3. The expandable apparatus of claim **1**, wherein the valve comprises:

a valve sleeve disposed within the inner bore of the tubular body and including at least one aperture in communication with the lower annular chamber;

a rotationally movable valve cylinder comprising a bore for providing a flow constriction, the valve cylinder disposed within the valve sleeve; and

a spring configured and disposed to exert an axial, upward bias force on the valve cylinder.

4. The expandable apparatus of claim **3**, wherein the valve cylinder is coupled to the valve sleeve by at least one pin carried by one of the valve sleeve and the valve cylinder engaged with a track located in the other of the valve sleeve and the valve cylinder, the at least one pin and the track, in combination, configured to control rotational and axial movement of the valve cylinder within the valve sleeve responsive to the upward bias force of the spring and selected application of an axial, downward force provided by drilling fluid flow through the bore of the valve cylinder.

5. The expandable apparatus of claim **4**, wherein the valve sleeve comprises at least one valve port alignable with the at least one aperture to communicate drilling fluid from the fluid passageway to the lower annular chamber responsive to at least one of rotational and longitudinal movement of the valve cylinder within the valve sleeve.

6. The expandable reamer apparatus of claim **1**, wherein the fluid passageway comprises:

at least two fluid ports longitudinally offset from each other, extending through a sidewall of the fluid passageway and coupling the fluid passageway to the upper annular chamber; and

a necked down orifice disposed longitudinally between the at least two fluid ports.

7. An expandable apparatus, comprising:

a tubular body comprising a fluid passageway extending through an inner bore;

a push sleeve disposed within the inner bore of the tubular body and coupled to one or more expandable features, the push sleeve comprising an upper annular surface in communication with an upper annular chamber between the push sleeve and the tubular body and a lower annular surface in communication with a lower annular chamber between the push sleeve and the tubular body, wherein the lower annular surface has a larger surface area than the upper annular surface, the push sleeve configured to move axially responsive to a flow of drilling fluid through the fluid passageway and into the lower annular chamber to extend the one or more expandable features; and

a valve within the tubular body configured to selectively control the flow of drilling fluid from the fluid passageway into the lower annular chamber, wherein the valve comprises:

a valve sleeve comprising at least one valve associated with a valve port that extends between the fluid passageway and the lower annular chamber;

an actuation device within the tubular body and separate from the push sleeve coupled to the at least one valve to selectively open and close the at least one valve; and

a controller operably coupled to the actuation device and configured to change a state of the actuation device in response to a command signal.

8. The expandable reamer apparatus of claim **7**, wherein the actuation device comprises a servo motor or a solenoid.

9. A method of operating an expandable apparatus, comprising:

flowing a drilling fluid through a fluid passageway in a tubular body of an expandable apparatus;

exerting a force on a push sleeve disposed within the tubular body sufficient to bias the push sleeve axially downward and to retract the one or more expandable features coupled to the push sleeve, wherein exerting a force on the push sleeve sufficient to bias the push sleeve axially downward comprises exerting the force with the drilling fluid flowed into an upper annular chamber between the push sleeve and the tubular body and on an upper surface of the push sleeve in communication with the upper

annular chamber between the push sleeve and the tubular body, the upper surface of the push sleeve comprising a smaller surface area than a surface area of the lower surface of the push sleeve;

opening a valve coupled to a valve port that extends between the fluid passageway and a lower annular chamber, and flowing the drilling fluid into the lower annular chamber in communication with a lower surface of the push sleeve disposed therein; and

exerting a force with the drilling fluid on the lower surface of the push sleeve and moving the push sleeve axially upward to expand the one or more expandable features coupled to the push sleeve.

10. The method of claim **9**, wherein opening the valve coupled to the valve port comprises:

biasing a valve cylinder disposed within a valve sleeve downward in response to the force applied on the valve cylinder by the flowing drilling fluid.

11. The method of claim **10**, further comprising:

reducing the flow rate of the drilling fluid;

biasing the valve cylinder upward in response to a force exerted by a spring coupled to the valve cylinder and at least partially rotating the valve cylinder;

increasing the flow rate of the drilling fluid; and

biasing the valve cylinder downward in response to a force applied on the valve cylinder by the flowing drilling fluid and at least partially rotating the valve cylinder.

12. The method of claim **9**, wherein opening the valve coupled to the valve port comprises:

communicating a command signal to a controller; and

changing the state of the valve in response to the command signal.

13. The method of claim **12**, wherein communicating the command signal to the controller comprises rotating the expandable reamer according to at least one combination of parameters including rotational speed of the expandable apparatus or a drill string secured thereto, axial movement of the expandable apparatus or a drill string secured thereto, flow rate of drilling fluid through a drill string secured to the expandable apparatus, flow or absence of flow of drilling fluid through a drill string secured to the expandable apparatus, and time.

14. An expandable apparatus, comprising:

a tubular body comprising a fluid passageway extending through an inner bore;

a push sleeve disposed within the inner bore of the tubular body and coupled to one or more expandable features, the push sleeve comprising a lower surface disposed in a lower annular chamber between the push sleeve and the tubular body and configured to move axially responsive to a flow of drilling fluid through the fluid passageway to extend and retract the one or more expandable features; and

a valve independent of the push sleeve within the tubular body configured to selectively control the flow of drilling fluid from the fluid passageway into the lower annular chamber.

15. The expandable apparatus of claim **14**, wherein the valve comprises a stationary valve sleeve having a longitudinally movable trap disposed therein and configured to obstruct one or more fluid ports extending between the fluid passageway and the lower annular chamber while passing a fluid through a central portion thereof.

16. The expandable apparatus of claim **15**, wherein the trap is configured to trap a flow restricting element on a seat located in a bore thereof and is releasable from the valve sleeve responsive to axially downward fluid pressure when the flow restricting element is on the seat.

17. The expandable apparatus of claim **16**, further comprising a catcher located within the inner bore below the valve and sized to receive at least one trap and one flow restricting element therein.

18. An apparatus for use downhole, comprising:

an actuation device configured to actuate a downhole device disposed within drilling fluid in a wellbore, the actuation device including:

a chamber formed between a housing and a movable member and containing a first substantially non-compressible fluid therein in isolation from the drilling fluid;

the movable member fixed to an annular member dividing the chamber into a first chamber section and a second chamber section;

the housing comprising at least one port through a wall thereof;

the movable member comprising at least one port through a wall thereof alignable with the at least one port through the wall of the housing; and

a control unit configured to permit movement of the first substantially non-compressible fluid between the first chamber section and the second chamber section, wherein when the first substantially non-compressible fluid is permitted to move substantially into the first chamber section the at least one port through the wall of the movable member is alignable with the at least one port through the wall of the housing to enable drilling fluid to be supplied to actuate the downhole device and when the first substantially non-compressible fluid is permitted to move substantially into the second chamber section the at least one port through the wall of the movable member is misalignable with the at least one port through the wall of the housing to prevent supply of the drilling fluid.

19. The apparatus of claim **18**, wherein the movable member includes a through passage for flow of the drilling fluid therethrough and wherein the flow of the drilling fluid through the actuation device is enabled to move the movable member to align the at least one port through the wall thereof with the at least one port through the wall of the housing when the control unit permits flow of the first fluid between the second chamber section and the first chamber section.

20. The apparatus of claim **19**, further comprising a biasing member configured to move the movable member in opposition to a direction of flow of the drilling fluid when a force of flow of drilling fluid through the actuation device is reduced below an opposing force applied to the movable member by the biasing member and the control unit permits movement of the first substantially non-compressible fluid between the first chamber section and the second chamber section to misalign the at least one port through the wall of the movable member and the at least one port through the wall of the housing.

21. The apparatus of claim **18**, wherein the downhole device is selected from a group consisting of: an expandable reamer; a force application member to apply force to a wellbore wall; an anchor configured to clamp the downhole device to a wellbore wall; and an adjustable stabilizer.

22. The apparatus of claim **18**, further comprising a telemetry unit comprising structure configured to send a first signal to the control unit to activate the downhole device and a second signal to the control unit to deactivate the downhole device, wherein each command signal comprises a pattern recognition signal detectable by at least one sensor associated with the control unit.

23. The apparatus of claim **22**, wherein the structure of the telemetry unit is configured to send the signals comprising at least one of rotation of a tubular coupled to the control unit, axial movement of a tubular coupled to the control unit, a flow rate of drilling fluid through a tubular coupled to the control unit, drilling fluid pressure in a tubular coupled to the control unit, and a presence or absence of drilling fluid flow through a tubular coupled to the control unit.

24. A method of performing a downhole operation, comprising:

placing a downhole device configured to attain an activated state and a deactivated state in a wellbore;

placing an actuation device that includes a first chamber and a second chamber, wherein when a first substantially non-compressible fluid is moved substantially into the first chamber under applied force of a second fluid flowing through the actuation device, the second fluid is enabled to be supplied from the flow thereof through the actuation device to a location within the downhole device external to the actuation device and otherwise isolated from flow of the second fluid through the actuation device to actuate the downhole device and when the first fluid is moved substantially into the second chamber under applied biasing force in excess or absence of any force of the second fluid flowing through the actuation device, the supply of the second fluid is stopped to enable the downhole device to deactivate; and

moving the first substantially non-compressible fluid between the first chamber and second chamber by selective application of the applied second fluid force to selectively activate and deactivate the downhole device.

25. The method of claim **24**, wherein selectively moving the first substantially non-compressible fluid comprises using a controller to enable movement of the first substantially non-compressible fluid between the first and second chambers.

26. The method of claim **25**, further comprising sending signals to the controller to initiate movement of the first fluid between the first chamber and the second chamber.

27. The method of claim **26**, wherein sending signals comprises sending pattern recognition signals.

28. An apparatus for controlling a downhole tool, comprising:

a tubular housing including an annular chamber and a first port in fluid communication with a tool to be activated;

a piston configured to move axially inside the tubular housing, wherein the piston and the tubular housing are mutually biased by a biasing member, the piston comprising:

a bore for flow of drilling fluid through the piston;

a second port configured to enable fluid communication from the bore to the first port at a selected axial position of the piston; and

an annular member within the annular chamber of the tubular housing dividing the annular chamber into a first chamber and a second chamber, and

a flow control device configured to allow or prevent a respective amount of fluid isolated from drilling fluid within the piston in the first chamber and the second chamber to change by allowing or preventing flow between the first chamber and the second chamber based on detected pattern commands;

wherein, when the first chamber is substantially filled with the isolated fluid the second port is aligned with the first port, and when the second chamber is substantially filled with the isolated fluid, the second port is out of alignment with the first port.

29. An actuation device for use downhole, comprising:

a housing including an annular chamber and a first port in fluid communication with a chamber of a tool;

a locking device; and

a piston configured to move axially inside the housing, wherein the piston is axially biased with respect to the housing by a biasing member, the piston comprising:

a bore for flow of drilling fluid through the piston;

a nozzle at one end of the piston, the nozzle being configured to utilize a flow of drilling fluid to provide an axial force to the piston;

a second port configured to enable fluid communication from the bore to the first port at a selected axial position of the piston; and

an annular member positioned within the annular chamber of the housing and coupled to the piston, wherein the locking device is configured to control axial movement of the piston by selectively locking and unlocking movement of the annular member within the annular chamber.

30. The device of claim **29**, wherein the annular member sealingly divides the annular chamber into a first chamber and a second chamber, and wherein the locking device comprises a flow control device in fluid communication with the first and second chambers to lock and unlock the annular member by controlling a respective amount of fluid in the first and second chambers.

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